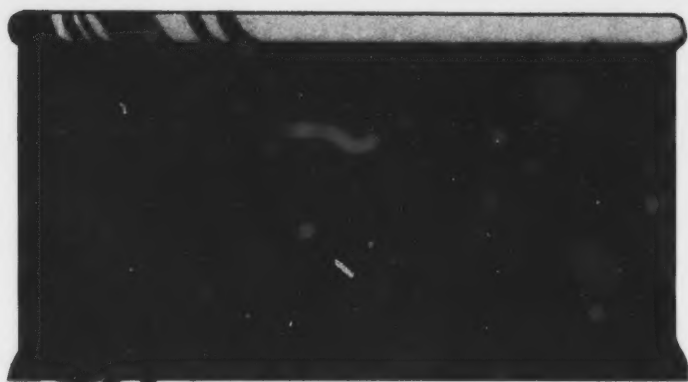




James N. Tanner and Anthony E. Reinsch

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**CANADIAN
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RESEARCH
INSTITUTE**

**CANADIAN CRUDE OIL
SUPPLY/DEMAND BALANCES**

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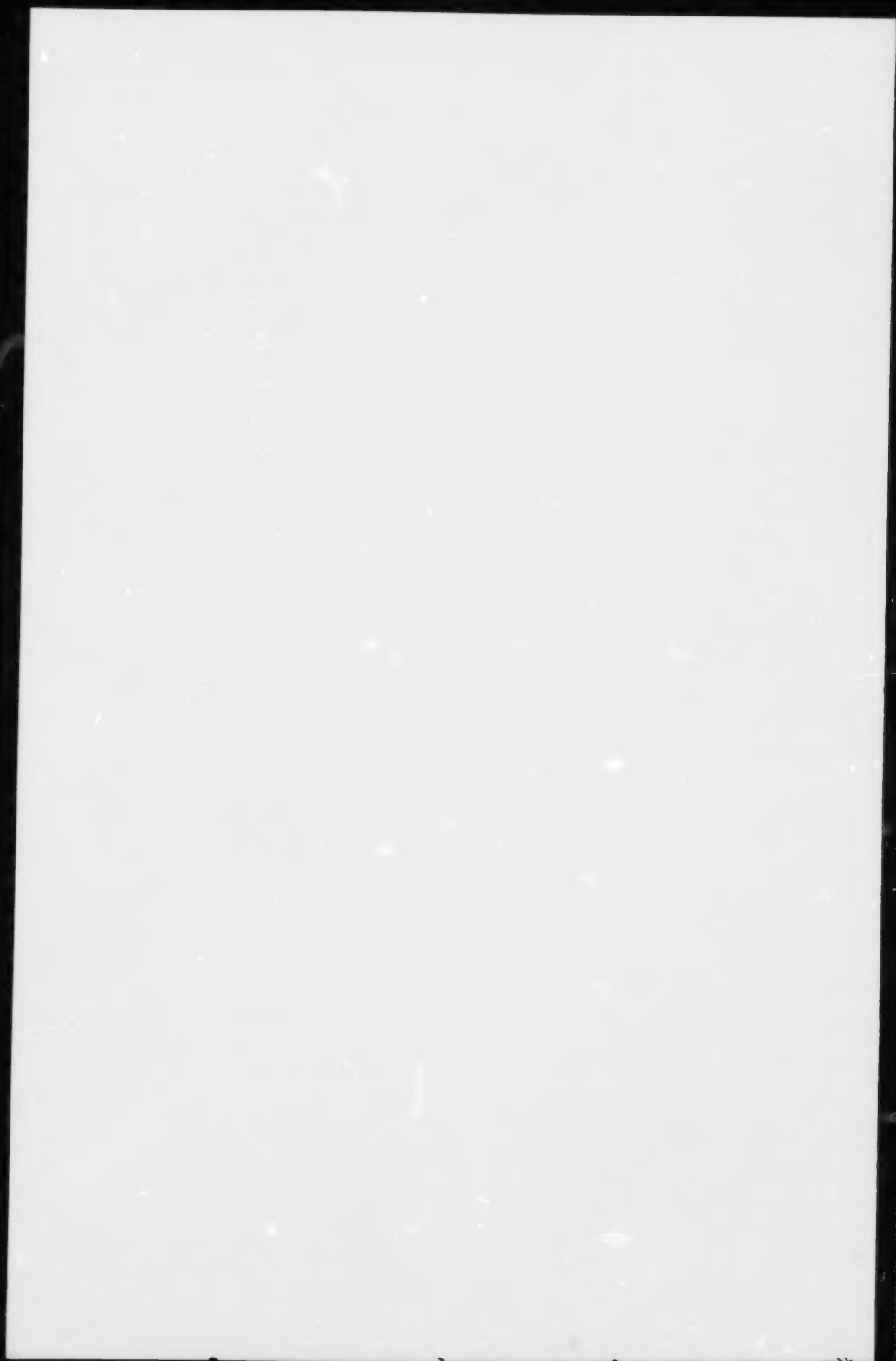
Preface

The second half of the 1980s has been a period of surplus capacity and excess production in the world oil market; of weak and unstable crude oil prices; and of rising refined petroleum product demand. The spectre of \$80 oil prices and concern over rising oil import bills have gradually dissipated in this environment of crude oil surplus. In Canada, industry and government initiatives to advance the development of nonconventional and frontier sources of crude oil have been met with a certain public skepticism, where not long ago these projects were viewed as critical to the country's continued economic prosperity.

It was in this environment of security over energy supply that the Institute's Board of Directors approved this examination of crude oil supply-demand balances in Canada. As this study shows, the reality of Canada's looming shortfall in conventional crude oil production has not dissipated along with the public concern over security of oil supply.

The authors of this study would like to first acknowledge the valuable work being carried out by the Alberta Research Council (ARC) and, in particular, the contributions to this body of research of Drs. Sam Wong, Surrinder Singh and Don Quon of the Oil Sands Research Department. The ARC suite of energy models is a valuable provincial resource in the field of energy market research and analysis. The authors also express their gratitude to the five-person Advisory Committee of government and industry representatives for the direction and insights provided over the course of this research program, and for their critical appraisal of the study results.

Special thanks are due to a number of Institute staff, including Beverly Kovacs and Janice Morrison, who processed the interim drafts and final manuscript; Megan Murphy, who developed the graphics contained in the study; and Zaytoon Janjua and Wendy Faid of the I.N. McKinnon Memorial Library, who gathered much of the source material for our research. A special acknowledgement is extended to Ted Ingram, who was responsible for much of the preliminary research on Canadian petroleum product demand. Finally, our thanks to our colleagues Michelle Heath and Michele McLachlan for their careful review and insightful comments.



EXECUTIVE SUMMARY

Developments in the world and Canadian crude oil markets have relegated the once contentious issue of security of domestic crude oil supply to secondary status in the ongoing Canadian energy debate. Persistent surplus crude oil production and excess productive capacity, weak and unstable oil prices, and low petroleum product demand have combined to lessen the concern of Canadians over future sources of oil supply. The availability of plentiful sources of natural gas, coal and electricity serve to reinforce this sense of energy security.

The volatility of the world oil markets, as witnessed over the last two decades, suggests that it would be myopic to believe that the current situation will continue. Over the 1987-89 period we have seen a revival of petroleum product demand growth worldwide, in response to lower crude prices. Canada, as with most industrialized countries, has reached a point at which the near-term potential for petroleum product conservation and energy efficiency gains have largely been exhausted. Future improvements will most likely accompany the gradual replacement of the capital stock, while economic growth will tend to increase demand for all energy sources. Results of a CERI analysis focussing on industrial natural gas demand reinforce this projection of increasing petroleum product demand.¹

A recent CERI analysis of the world oil market concluded that under reasonable assumptions regarding global economic conditions, remaining recoverable crude oil resources, and production decisions on the part of the Organization of Petroleum Exporting Countries (OPEC), the current surplus supply conditions dominating the world oil market could be gradually worked off as we move through the 1990s.² The second half of that decade would be characterized by accelerating inflation-adjusted increases in crude oil prices, as non-OPEC established reserves of crude oil were gradually depleted and OPEC regained market share and market control.

Canada is not an exception to this underlying premise of gradually depleting global reserves of, in particular, light crude oil. The National Energy Board staff report, Canadian Energy Supply and Demand: 1987-2005, concluded that under a high price scenario which forecasts a crude oil price of \$30 per barrel (in 1987 \$U.S.) at the turn of the century, Canada would be importing 17 thousand cubic metres

per day (106.9 thousand barrels per day) of light crude oil in 2000, with peak imports of 41 thousand cubic metres (258 thousand barrels) per day reached in 1995. Under a low price scenario of \$18 per barrel in 2000, the light oil import requirement would exceed 70 thousand cubic metres (440 thousand barrels) per day in 2000 and would be rising as we enter the next century.³

This study examines the existing situation pertaining to crude oil supply and refined petroleum product demand in Canada and, based on reasonable assumptions regarding future energy prices and economic development, provides an analysis of likely future paths of crude oil supply-demand balances. An important component of this research is the assessment of conventional, nonconventional and frontier sources of crude oil supply (discussed in Chapters 3 and 4) and an evaluation of the oil megaproject agreements announced in 1988 (discussed in Chapter 6) which are, in part, a response to the concern over increasing exposure of the Canadian economy to imports of foreign light crude oil. The supply projections are set against a forecast of Canadian refined petroleum product demand (discussed in Chapter 2) and the resulting light and heavy oil balances are examined in Chapter 6.

The remainder of this summary will focus on the results of our research concerning the development profiles for Canada's crude oil resources, the accompanying crude oil supply-demand balances, and the conclusions and recommendations arising from this research program.

Crude Oil Development Profiles

The analysis of crude oil supply developments covers all current and potential sources of conventional, nonconventional and frontier crude oil, broken down into light and heavy crudes. A suite of energy models developed by the Oil Sands Research Department of the Alberta Research Council (ARC) was used to generate the development profiles and supply-demand balances, based on input assumptions and parameters developed at CERL. The ARC energy models, discussed in some detail in Appendix A, are a powerful tool for analysis of energy market developments, comparative energy supply technologies, and inter-commodity competition within the energy sector.⁴

The objective of our analysis of crude oil development profiles is to identify efficient strategies for production of Canada's petroleum resources, given stand-alone project economics. The

analysis is based on three alternative world oil price forecasts and two alternative assumptions regarding industry behaviour.

The world oil price forecasts, shown in Figure 1, were developed using the CERI World Oil Market Model. The base case scenario extends the existing oil market structure and the existing political realities out into the future, with no major changes other than general resource depletion and consumption of world oil reserves.

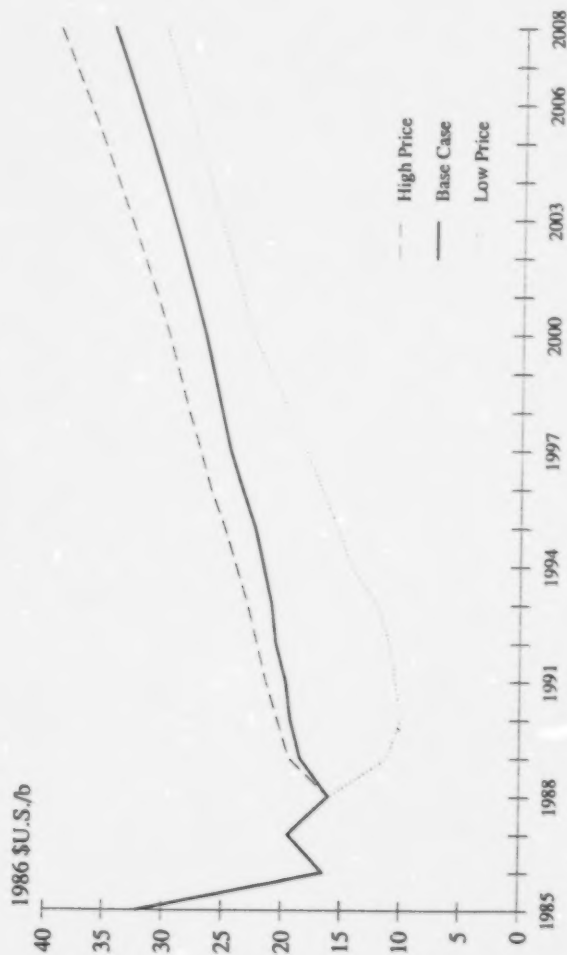
The low case scenario is designed to reflect the potential downside price risk associated with a competitive world oil market. Finally, the high case is constructed to identify the possible technologies which the Canadian oil industry could bring into production, if world oil prices rise to sufficiently high levels. This high price case is useful in the ranking of marginal sources of oil supply. The resulting price spread--\$23 to \$30 per barrel in 2000 and \$30 to \$39 per barrel in 2008 for WTI in Chicago, expressed in 1986 \$.U.S.--represents a realistic range for future oil prices.

The assumptions regarding industrial behaviour are labelled "prudent industrial behaviour" and "perfect foresight." Under the former, industry decision-makers are assumed to develop a particular project only if the price of crude oil has reached or exceeded the per barrel break-even cost (or internal hurdle rate) for that project. All project economics are developed assuming a 12 percent real rate of return to the project (see Chapters 3 and 4 and Appendix F for a detailed discussion of the costs and economics of the various supply sources analyzed in this study). For sensitivity purposes, results are also reported under alternative rate of return assumptions, from 0 to 15 percent.

Under the perfect foresight assumption, decision-makers are able to predict future prices and costs of domestic and world oil supply. In these circumstances, a company can efficiently pre-build and operate projects so as to optimize profits arising from production. Both assumptions are realistic, with the former representing a risk averse investor and the latter providing a test for the optimal timing of various projects.

The summary crude oil development profiles arising from the three crude oil price scenarios, assuming prudent industrial behaviour and a 12 percent real rate of return, are shown in Figure 2. The important observations to draw from this diagram are the significant decline in crude oil supply through the mid-1990s, even under the

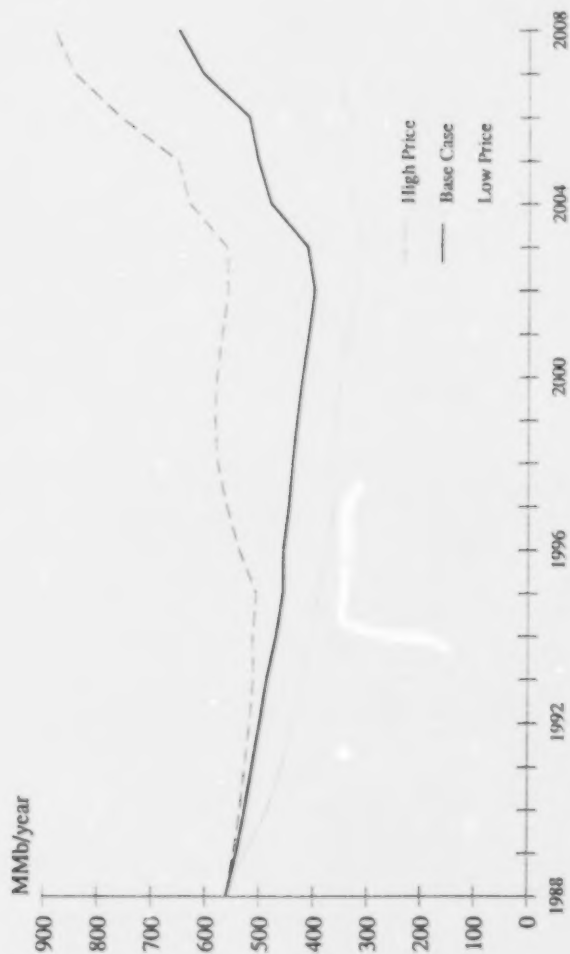
Figure 1
Crude Oil Price Scenarios



SOURCE: CERL

Note: Prices for West Texas Intermediate crude, delivered in Chicago, Illinois.

Figure 2
Canadian Crude Oil Development Profiles
All Sources, by Price Scenario



SOURCE: CERL, Alberta Research Council.

high price scenario, and the considerable price response in domestic crude oil supply. Total crude oil and equivalent production in 2008 ranges from 377 to 884 million barrels per year under the low and high price scenarios, respectively.

It is important to note that almost three-quarters of this differential in crude oil production is accounted for in synthetic and frontier sources of light crude oil (see Appendix D). These sources constitute over 70 percent of total domestic crude oil supply in 2008 under the high price case, versus 61 percent under the low price case. This result also points to the significant decline in light/medium crude oil production from the Western Sedimentary Basin (WSB). While production from the WSB declines throughout all three price scenarios, it is important to note that the variance between the low and high price cases is approximately 100 million barrels per year in 2008. This represents the possible difference in production after 20 years of either very weak or very strong prices. To place this figure in perspective, 100 million barrels per year represents more production than any individual megaproject currently proposed.

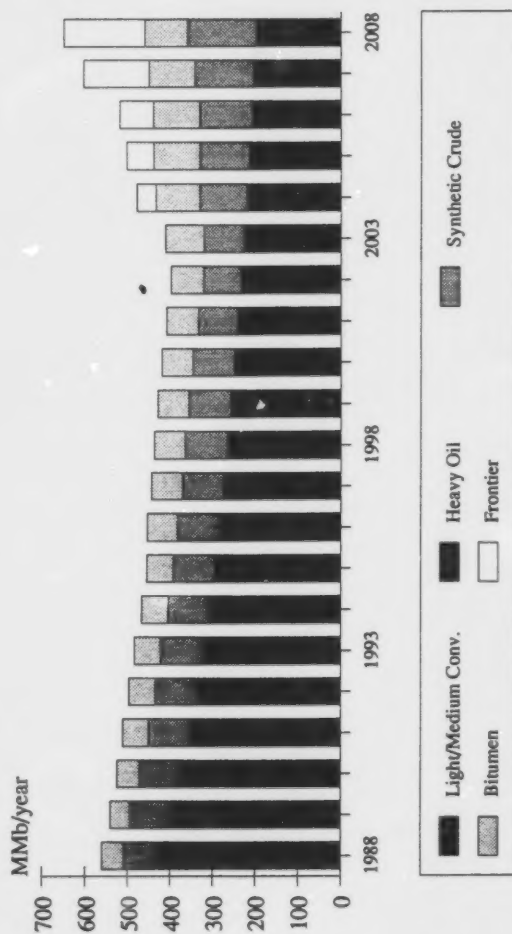
A detailed development profile by crude oil source is provided in Figure 3 for the base case price scenario. This figure clearly shows the decline in conventional light/medium and heavy crude oil production. For light crude, this is a consequence of declining average discovered pool size and reservoir depletion, characteristic of a mature resource basin. Synthetic crude oil production begins to pick up after the year 2000, but the general decline in light crude production is not reversed until frontier production is initiated, late in the forecast period.

Crude Oil Supply-Demand Balances

To analyze the balance of light and heavy crude oil supply and demand in Canada, regional refined petroleum product demand scenarios were developed as input to the ARC energy models. The demand scenarios, discussed in Chapter 2 and detailed in Appendices E and G, were developed at the Institute using the CERI Canadian Regional Energy End-Use Demand (CREED) model.

Figure 4 provides light crude oil balances under the base case price scenario. The decline in conventional light/medium oil production is partially offset through increases in synthetic and frontier production, beginning in 2006 and 2008, respectively. The upward trend in net crude oil import volumes is reversed in 2003 and import

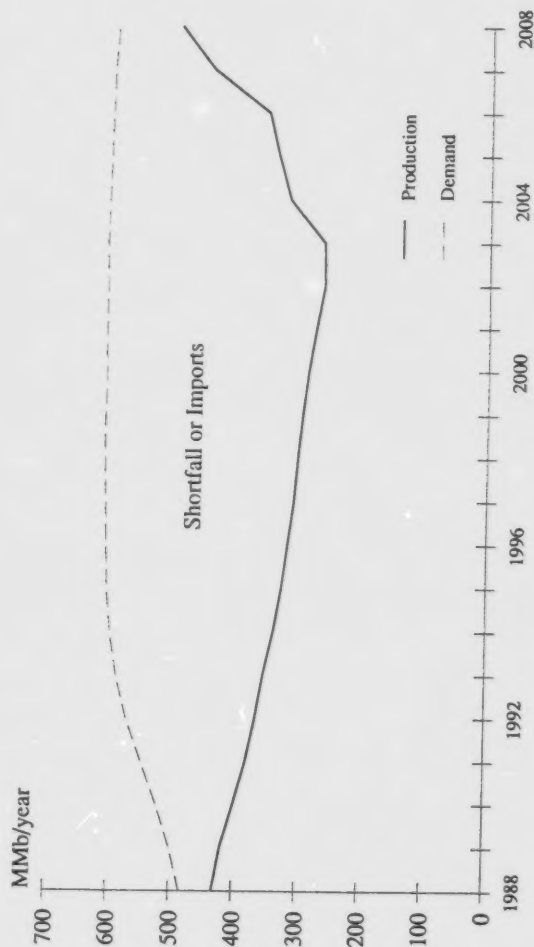
Figure 3
Production Summary - All Sources
Base Case



SOURCE: CERL

Note: See Appendix "D" for source data.

Figure 4
Canadian Light Oil Balances
Base Case



SOURCE: CERL

Note: See Appendix "E" for source data.

volumes decline significantly over the duration of the forecast period. However, Canada continues to be unable to meet its internal demand for light crude oil products. Light oil imports peak at 347 million barrels per year and decline to just under 100 million barrels per year by 2008.

Heavy blend balances under the base case price scenario are summarized in Figure 5. Canada is a major exporter of heavy blend through most of the forecast period. However, demand from the Co-op and proposed Lloydminster upgraders gradually limit the volume of heavy crude available for the export market. Heavy blend exports peak at 105 million barrels per year in 1997 and are virtually eliminated by the end of the forecast period.

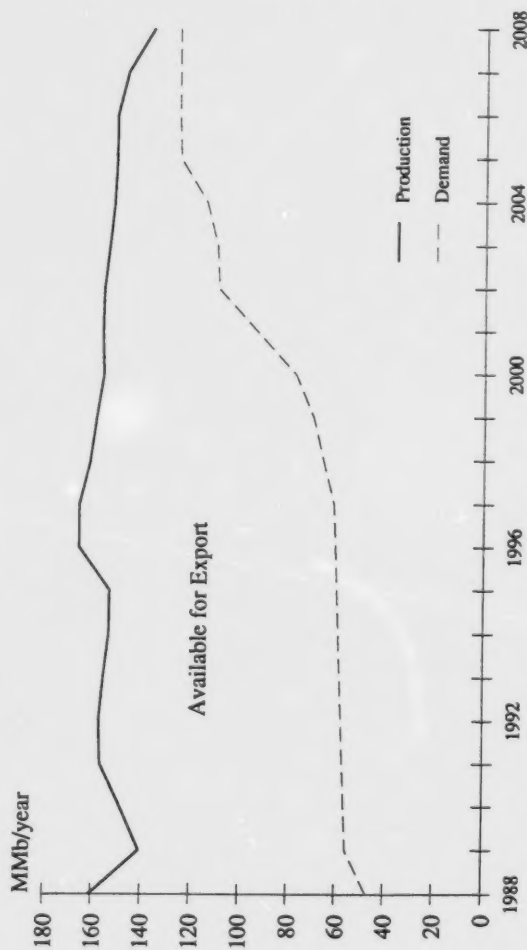
Net crude oil imports peak in 2003 at just over 300 million barrels per year and decline to 90 million barrels per year by the year 2008.

Timing of the Megaprojects

Projections of a continued shortfall in Canadian light crude oil production were addressed through the announcement of three energy megaprojects in 1988. The Hibernia oil field off the coast of Newfoundland is expected to produce an average of 110,000 barrels per day of light crude oil from an estimated reserve of 525-650 million barrels of recoverable oil, at a development cost of \$8.5 billion. Construction is scheduled to begin in 1990 with a projected in-service date of 1994.

The other megaprojects are directed to exploitation of heavy oil and bitumen reserves in western Canada. The OSLO Alberta Oil Sands Project is an integrated mined oil sands plant designed to produce 77,000 barrels per day of synthetic light crude oil. Initial capital cost of the plant is estimated at \$1.4 billion. Construction is scheduled to begin in 1991 with an in-service date of 1996. The Lloydminster heavy oil upgrader will process heavy oil and bitumen feedstock into synthetic light crude oil. The plant is designed to produce 46,000 barrels per day of synthetic crude at an estimated capital cost of \$1.26 billion. Construction is scheduled to begin in 1990 with an in-service date of 1993. Chapter 5 and Appendix F provide a detailed description of each of these projects and a comparative assessment of their project economics.

Figure 5
Canadian Heavy Blend Balances
Base Case



SOURCE: CERL.

Note: See Appendix "E" for source data.

The in-service dates contained in the project announcements represent a considerable advance in timing of development relative to the base case model simulation results. In our analysis, under the prudent industrial behaviour decision criterion and stand-alone project economics based on a 12 percent real rate of return, the OSLO oil sands plant does not come into production until 2010. The Hibernia oil field is brought into service in 2006, while the Lloydminster upgrader begins production in 1998. Interestingly, production is initiated in the Beaufort Sea region in 2004, two years before Hibernia (see Appendix D.2).

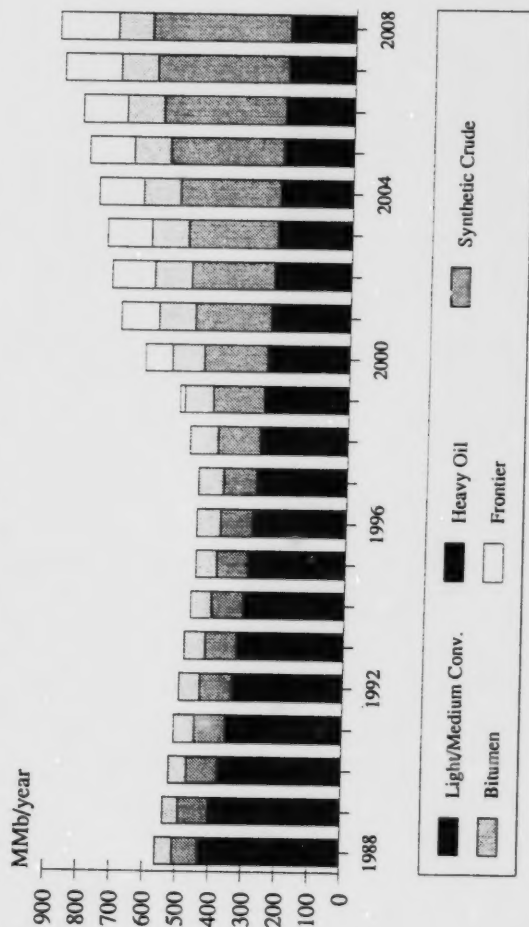
The reality, of course, is that the various project announcements do not present the outcome of stand-alone economic analysis. By lending the financial support of the Canadian public to the projects, the federal and various provincial governments involved in these ventures have effectively taken on a significant share of the downside price risk associated with the megaprojects.

This situation is proxied by analyzing a "perfect foresight" scenario under the base case price forecast, in which project developers are assumed to know with certainty the path of future oil prices and hence will prebuild facilities to optimize returns from production. The crude oil development profile generated under this scenario is shown in Figure 6. In all cases, the megaprojects are brought onstream earlier than under the prudent industrial behaviour case. Hibernia is advanced to 2004, the Lloydminster upgrader begins production in 1998 at a much higher initial volume, and the OSLO project is advanced to 1997, only one year later than the in-service date provided in the project announcement.

These developments underline the critical role of crude oil price expectations in the policy decision to accelerate development of Canada's nonconventional and frontier oil resources. The costs of an incorrect guess could be substantial. If we delay development of these resources, we will be increasing our exposure to foreign imports and dependence on foreign oil supplies, which could rise abruptly in price. In a deregulated market environment, the cost would be the revenue and economic stimulus foregone by not having the projects in place.

Alternatively, if these projects are accelerated in advance of market prices sufficient to justify their undertaking (as is the current development strategy) and oil prices do not rise to meet the project hurdle rates, Canada risks losing a substantial portion of this capital

Figure 6
Production Summary - All Sources
Perfect Foresight - Base Case Prices



SOURCE: CERL

Note: See Appendix "D" for source data.

investment. To the extent that the public sector is involved in these megaproject developments, the risk will be borne by all Canadians.

Conclusions and Recommendations

This study has confirmed the findings of other analyses of Canada's conventional crude oil resources that, under a reasonable forecast of crude oil prices, Canada will face a decline in conventional crude oil production through the 1990s and, of particular concern, a rapidly growing deficit in light crude oil balances. Recent discoveries in British Columbia provide support for the view that there remain significant undiscovered pools of hydrocarbon reserves in the Western Sedimentary Basin which could temporarily delay the decline in light crude oil production. However, it is expected that the costs of finding these resources will increase over time, due partly to the decline in average discovery pool size.

Canada therefore faces a supply dilemma. Should we invest now in development of nonconventional and frontier sources of light crude oil, which will yield predictable volumes of expensive crude oil, or should we postpone development until we are more certain of the medium-term trends in world oil prices? Alternatively, should we refocus energy policy towards more intensive and extensive development of the remaining oil in place in the Western Sedimentary Basin, and towards proving up of the undiscovered resources believed to remain in the Basin?

Megaproject development dominated the focus of oil policy in 1988. The costs of these megaprojects have been discussed in this study from many different angles. An important conclusion arising from the analysis is that these costs are generally higher than the costs of producing conventional light and heavy oil from the Western Sedimentary Basin.

It is likely that there are substantial quantities of conventional oil available from this basin at lower costs than either OSLO or Hibernia. The incentives that may be required to increase conventional production from the Western Sedimentary Basin may not be as simple as megaproject incentives, but they may be more cost effective.

It is a recommendation of this study that conventional sources of light and heavy crude oil, including EOR, be reviewed to determine optimal levels of incentives; that these incentives be designed to promote the extraction of less

expensive sources of crude oil before more expensive sources; and that these incentives be designed to maintain the productive capacity of the Western Sedimentary Basin as much as economically possible. Further, such incentives should be based upon a consistent long-term policy rather than a series of short-term band-aid programs.

The potential exists in the conventional areas to continue to contribute significantly to Canadian requirements of light crude oil. Canadian public policy should be directed to optimizing investments in this major resource.

Canada also has enormous supplies of heavier crude oil products. This resource is only partially accessible under current technology because of the high costs of extraction and processing. A major goal of this study was to investigate just how accessible such supplies are.

The conclusion is that the costs of producing major portions of the bitumen and oil sands deposits are consistent with, or even less expensive than, other major Canadian frontier megaprojects.

It is a recommendation of this paper that if Canada is confronted with a major shortfall of supplies of light crude oil, then careful consideration should be made to environmentally sensitive extraction and upgrading of bitumen and oil sands resources; and that extraction and upgrading research focus on methods which allow smaller incremental capital requirements in order to diminish the risk of volatile world oil prices.

The analysis of frontier resources provided in Chapter 5 suggests that Beaufort Sea production is very close to Hibernia production in per barrel cost. However, Hibernia has been chosen as the more immediate productive source notwithstanding the additional future potential of the Beaufort Sea region.

This decision is based largely upon the economic impact of the Hibernia project on the economy of the Atlantic provinces. The economic development aspects of the project provide policy makers with a rationale for subsidization of the Hibernia project.

Similar arguments could be made for opportunities in the Beaufort Sea. However, the population of the northern territories is considerably less than that of Atlantic Canada and hence commands

somewhat less policy attention. In addition, the obligation on the part of the Government of Canada to the reduction of regional economic disparities among the partners in Confederation does not apply equally to the northern territories.

Beaufort Sea opportunities should be studied with the goal of determining the optimal investment and social timing for this important Canadian resource.

Finally, a comment on the recently signed Free Trade Agreement between Canada and the United States. This study has not analyzed or included current trade barriers or the effects of the Free Trade Agreement. However, if world oil prices remain low, Canada will require increasing volumes of light oil imports. The Free Trade Agreement proposes that Canada continue to export the proportion of oil it now exports to the United States and that, if we choose to cut back on production of this declining resource, we must cut back in equal proportions between Canadian consumption and exports to the United States. The authors have no particular concern over this provision, viewing it as a special consideration between favoured trading partners.

This provision, however, was established to accommodate world shortages in oil. Canada, on the other hand, will experience a shortage in light crude oil under conditions of low crude oil prices and surplus global light oil supply. In addition, Canadians have agreed to subsidize the development of nonconventional and frontier sources of light oil in Canada. This subsidy is permitted in the Free Trade Agreement. If the price of oil remains low and we are required to continue to export a constant proportion of light crude oil to the U.S., then actions taken to advance nonconventional or frontier light crude oil production would be tantamount to Canadian taxpayers subsidizing U.S. oil consumers.

These and other issues relating to future development of Canada's hydrocarbon resources will come under increasing scrutiny as we move through the 1990s. Certainly, the potential subsidization of light crude oil exports begs analysis and policy review and resolution, before it develops into a policy problem. The challenge to both industry and government is to pursue the most efficient and economic development and exploitation of Canada's crude oil resources.

Footnotes

¹M. Heggelund, Industrial Natural Gas Demand (Calgary: Canadian Energy Research Institute, 1989) pp. 169-192.

²A. E. Reinsch; K. J. Brown; and J. O. Stanford, Stability Within Uncertainty: Evolution of the World Oil Market (Calgary: Canadian Energy Research Institute, 1988), pp. 158-160.

³National Energy Board, Canadian Energy Supply and Demand: 1987-2005, (Ottawa: Supply and Services, 1988), pp. 70-71.

⁴Further information regarding the ARC suite of energy models and the potential for development and application of these models to particular technologies or sensitivity cases can be obtained through the Oil Sands Research Department, Alberta Research Council, 1021 Hayter Road, Edmonton, Alberta, Canada T6H 5X2.

Chapter 1

PERSPECTIVES ON CANADIAN CRUDE OIL SUPPLY AND DEMAND

1.1 Introduction

Developments in the world crude oil markets in the 1980s have relegated the once contentious issue of adequacy of Canadian crude oil supply to secondary status in the ongoing Canadian energy debate. The response of crude oil supply and demand to the rapid and largely artificial oil price increases of the 1970s produced an excess supply overhang in the world oil market, culminating in the dramatic decline in oil prices in 1986 (the third "price shock" in less than 15 years). Since that time, the world oil market has been characterized by weak and unstable oil prices, persistent surplus production and excess productive capacity, and (until 1988) low petroleum product demand growth. In such an environment, concern over the ability of domestic crude oil supply to meet crude oil demand has gradually abated, accompanied by the retreat of federal and provincial policy makers from the arena of domestic energy market regulation.

Despite the natural inclination to ignore supply concerns when prices are low and foreign sources of crude oil are plentiful, the experience of the last two decades has shown that this situation cannot be relied upon to continue. Social, political and economic factors can operate quickly to turn the market. A prudent analysis cannot afford to ignore the future Canadian oil supply-demand balance, given the considerable impact which large price swings can have on Canadian oil supplies and on the Canadian economy in general.

A recent CERI analysis of the world oil market concluded that under reasonable assumptions regarding global economic conditions, remaining recoverable crude oil resources, and production decisions on the part of the Organization of Petroleum Exporting Countries (OPEC), the current surplus supply conditions dominating the world oil market could be gradually worked off as we move through the 1990s.¹ The second half of that decade would be characterized by accelerating inflation-adjusted increases in crude oil prices, as OPEC regained market share and market control. A critical component of

this analysis was the gradual depletion of established reserves in the non-OPEC oil producing regions.

While one can question the timing of this market turnaround, it is difficult to argue against the underlying premise of gradually depleting global reserves of, in particular, light crude oil. In this regard, Canada is no exception. The National Energy Board staff report, *Canadian Energy Supply and Demand: 1987-2005*, concluded that under a high price scenario which forecasts a crude oil price of \$30 per barrel (in 1987 \$U.S.) at the turn of the century, Canada would be importing 17 thousand cubic metres per day (106.9 thousand barrels per day) of light crude oil, with peak imports of 41 thousand cubic metres (258 thousand barrels) per day reached in 1995.² Under a low price scenario of \$18 per barrel in 2000, the light oil import requirement would exceed 70 thousand cubic metres per day (440 thousand barrels) in 2000 and would be rising as we enter the next century.³

The frontier and nonconventional crude oil megaproject agreements announced in 1988 are, in part, a response to concern over increasing exposure of the Canadian economy to imports of foreign light crude oil and potential oil price fluctuations. These projects would provide substantial additional Canadian supplies of light crude oil and impact significantly on Canadian crude oil supply-demand balances.

The objective of this study is to analyze the existing conditions of crude oil supply and demand in Canada and, based on reasonable assumptions regarding future energy prices and economic growth, to investigate the future path of crude oil supply-demand balances. This is a complex area of analysis, involving various grades and qualities of oil being supplied to regions with diverse demand characteristics and requirements.

A number of issues and questions are addressed in this study. Given the relatively high cost of Canadian oil supplies in a global context, will Canada be able to meet projected increases in petroleum product demand? Will the slate of crude oils being produced match the demand for petroleum products? Or, alternatively, is the refining industry in Canada configured so as to accept Canadian crudes and supply the desired mix of products? Will Canada's supply of diluent be sufficient to accommodate continued marketing of heavy crude oil to the United States? Will a potential shortfall in diluent supply force the accelerated upgrading of Canada's heavy oil resources?

Canada's frontier resources and oil sands development will play a major role in future crude oil supply. If Canada is to realize the full economic benefits from exploitation of these resources, efficient timing of development will be of critical importance. What are the preferred development strategies for Canada's nonconventional and frontier oil resources? How would the recent development agreements affect these strategies? What is the likely return to the various partners in these agreements, and what is the role of the public sector in developing these resources?

These and other questions form the framework for analysis in this study. General recommendations have been developed after contemplating the results of the various simulations and analyses.

1.2 Methodology and Study Outline

The Canadian Energy Research Institute has collaborated with numerous technical and policy groups which have added greatly to the scope and depth of the Institute research program. For this study, CERI collaborated with the Alberta Research Council (ARC) in developing the analytical framework used to examine crude oil supply-demand balances in Canada. The ARC linear programming model, ALF01, was used as the basis for analysis of future oil supply scenarios in Canada, with CERI providing the appropriate supply inputs and petroleum product demand projections. The ALF01 framework is described in some detail in Appendix A of the study.

To develop the refined product demand scenarios underlying the analysis, CERI employed the Canadian Regional Energy End-Use Demand (CREED) model which CERI developed and maintains "in-house." The demand projections are disaggregated regionally, to be consistent with the ARC modelling framework. Western and Northern Canada are combined in the Western region, Central Canada includes Ontario and Quebec, and Atlantic Canada includes the four eastern-most provinces. Chapter 2 provides a discussion of petroleum product demand in Canada and outlines the macroeconomic and price assumptions employed in the study.

This study examines light, medium and heavy crude oil and diluent balances. An assessment of supplies in the Western Sedimentary Basin is provided in Chapter 3, and of the supply potential of the frontier regions in Chapter 4.

The supply-demand framework is combined and the resulting crude oil balance is discussed in Chapter 5. The results are predicated on the nonconstrained, or economic, development of conventional, nonconventional and frontier sources of oil supply, given various economic assumptions and demand paths. In Chapter 6, the three recently announced crude oil development proposals--Hibernia, the Lloydminster Upgrader, and the OSLO oil sands project--are discussed and analyzed in terms of timing of development, return to the project partners, and impact on Canadian crude oil supply-demand balances.

Finally, Chapter 7 provides a summary of the key research results and general recommendations regarding the future development of crude oil resources in Canada.

Footnotes

¹A. E. Reinsch; K. J. Brown; and J. O. Stanford, Stability Within Uncertainty: Evolution of the World Oil Market (Calgary: Canadian Energy Research Institute, 1988), pp. 158-160.

²National Energy Board, Canadian Energy Supply and Demand: 1987-2005 (Ottawa: Supply and Services, 1988), p. 70.

³*Ibid.*, p. 71.



Chapter 2

CANADIAN CRUDE OIL DEMAND

2.1 Introduction

The objective of our demand assessment is to provide an appropriate and consistent comparison with Canadian supply capabilities, both in absolute quantities and in regional availability. In order to achieve such a demand forecast we have used the Canadian Regional Energy End-Use Demand Model (CREED), supplemented by an historical review of regional oil demand characteristics in Canada. In addition, since demand for crude is derived from demand for the refined petroleum products, a discussion of petroleum product demand is provided.

2.2 Canadian Demand for Crude Oil

2.2.1 Price Effects

In a period of less than 15 years, Canadian consumers have contended with three major crude oil price shocks. The first two caused crude oil prices to increase significantly, with resulting price increases for refined products. The third price shock, in the first half of 1986, saw international reference crude prices fall by as much as 60 percent from their levels a year earlier. Real refined petroleum product prices also fell, although the changes in Canada were modified by taxes imposed upon refined products and by adjustments to refiners' and distributors' margins. While the average price of crude oil in Montreal fell by 45 percent, the price of motor gasoline only decreased by 19 percent. Similar price cuts affected most refined petroleum products throughout Canada, with the exception of aviation gasoline which actually increased in price due to increased taxes and margins.

The two crude oil price increases during the 1970s brought about major changes in consumption patterns of refined products. In a time span that encompasses the three price shocks, 1972 to 1987, Canada decreased its refined petroleum product demand by 8.5 percent, in spite of gains in population of 10 percent and growth in real economic output of over 36 percent. The decline in petroleum product demand in response to the 1973 and 1979 price increases involved

significant lag times, required to structurally adjust to the new price levels. Consumption changes were achieved through conservation and interfuel substitution, so that by the end of 1986, Canadian petroleum product consumption was only 88.9 percent of its 1972 level, for an average demand drop of -0.84 percent per year.¹

2.2.2 Regional Considerations - Northern Canada

Assessment of the relative dependence upon crude oil across regions varies in accordance with the measurement used. As an example, Canada's North consumes the least amount of refined petroleum products in absolute terms, but has the highest consumption level in per capita terms.

The two northern populations are totally dependent upon oil products for secondary energy, due to the lack of electricity from thermal, nuclear and hydro sources, and the absence of natural gas service. Despite the lower world oil and product prices, the decline in aggregate economic activity in this region for the second consecutive year resulted in lower refined product demand. This is particularly true of the Northwest Territories, which was adversely affected by the almost total suspension of oil exploration in the MacKenzie River delta and Beaufort Sea areas in response to lower crude oil prices.²

Although northern per capita refined product demand is the highest in Canada, several factors constrain it from reaching the higher levels that would be commensurate with the average socio-economic conditions prevailing in the country. The high cost of transportation is certainly a consumption deterrent, as transportation costs can comprise over half the price of the refined product in remote Arctic communities. The difficulty of transporting refined products is another factor. Because marine transportation is the cheapest mode, bulk fuels are usually shipped by barge. As that method of transportation is seasonal, there is a tendency to conserve supplies during the long winter period. Even some shipments of refined product by truck are seasonal because of the lack of permanent all-weather roads. For that reason, the output from the one refinery at Norman Wells has a distribution range restricted to the Mackenzie River basin--barges in the summer, and ice roads during the winter.

Demand for road transportation fuels is probably lower than it might otherwise be because of the isolation of many communities. Many are not connected by roads. Long distances between

communities and poor road conditions have the effect of suppressing travel where roads do exist. Therefore, transportation demand for refined products tends to be generated by necessity and purpose, as opposed to recreation and convenience as often occurs elsewhere in Canada.

Table 2.1 shows that on a per capita basis, northern consumption levels of diesel and gasoline exceed national levels. Diesel is used for marine transportation during the shipping season on the Mackenzie River and in the Arctic. It is also used to supply much of the electrical generation in the North. While figures for end-use consumption of diesel are not available, these two consumption categories explain much of the diesel fuel demand, which was almost four times greater than the average 1987 Canadian per capita demand.

Motor gasoline demand during 1987 was 14.3 percent above the Canadian per capita figure, notwithstanding the above discussion about reduced road transportation in the North. Two reasons help to explain the high demand for this product. Cold temperatures cause increased consumption by vehicles because of reduced fuel efficiencies per unit of distance travelled, longer engine warm-up periods, and the reluctance of drivers to turn engines off during extremely cold temperatures. The second explanation is the widespread use of all-terrain and snow machines for transportation. Total figures are unavailable for comparison, but the numbers of such machines in some isolated communities outweigh that of conventional vehicles. Unlike other parts of Canada where they are usually used for recreation, all-terrain and snow machines often replace the automobile as the primary form of transportation.

2.2.3 Regional Considerations - Atlantic Canada

The high dependence of the four Atlantic provinces upon imported crude oil is well known. The reasons behind this dependence include distance from major Canadian oil supplies, a lack of indigenous natural gas and related infrastructure, and limited hydro and nuclear electric generating capacity.³ On a per capita basis, total consumption of refined products in the Atlantic provinces in 1987 was 44.1 percent greater than the national level, and 53.1 percent greater than that of Ontario. The latter comparison is particularly significant, given that Ontario's industrial sector is more diverse and developed than that of the Atlantic region. In addition, Ontario's petrochemical industry requires larger volumes of oil derivative feedstock than does that of the Atlantic provinces.

TABLE 2.1
COMPARISON OF 1987 DOMESTIC PER CAPITA
SALES LEVELS OF REFINED PETROLEUM PRODUCTS^a
(cubic metres per person)

	Canada	Yukon and N.W.T.	Atlantic Provinces
Propane and propane mixes	0.068	0.000	0.071
Butane and butane mixes	0.029	0.000	0.012
Petrochemical feedstock	0.143	0.000	0.049
Naphtha specialties	0.011	0.004	0.003
Aviation gasoline	0.007	0.142	0.006
Motor gasoline	1.291	1.475	1.197
Jet fuel - kerosene type	0.152	0.353	0.137
Jet fuel - naphtha type	0.029	0.620	0.076
Kerosene	0.028	0.829	0.063
Diesel	0.611	2.439	0.673
Light fuel oil (LFO)	0.244	1.269	0.710
Heavy fuel oil (HFO)	0.270	0.386	1.326
Asphalt	0.117	0.034	0.104
Coke	0.500	0.000	0.001
Oils and greases	0.040	0.036	0.025
Other	<u>0.021</u>	<u>0.016</u>	<u>0.001</u>
TOTAL	3.116	7.604	4.452

SOURCES: Statistics Canada, Refined Petroleum Products, Catalogue 45-004, December 1987, and Canadian Statistical Review, Catalogue 11-003E, December 1987.

^aPopulation figures for 1987 were estimated by applying the 1986 growth rates to the 1986 Statistics Canada population estimates.

Of the 17 refined products listed in Table 2.1, Atlantic per capita sales are less than the national levels in all but six. The three heating products (LFO, HFO and kerosene) have consumption rates that greatly exceed national averages, which can be attributed to the absence of competitively priced alternatives such as natural gas. The fourth heating product, propane, had a 1987 sales level marginally above that of the national average. Diesel fuel demand was 10.1 percent greater than the national level on a per capita basis, due largely to marine transportation demands which are in addition to road and rail transportation and non-transportation end-use demands.⁴

Lower real petroleum product prices generated a significant demand response in Atlantic Canada in 1987. The level of aggregate sales increased by over 10 percent from that of 1986. Increased consumption was recorded for all but two refined products (light fuel oil and kerosene), with the most significant increases being for those products typically used in the industrial sector—petrochemical feedstock, 49.5 percent; heavy fuel oil, 29.7 percent; and coke, 100 percent.

2.2.4 Regional Considerations - Central Canada

Quebec and Ontario are also heavily dependent upon crude oil, although to a lesser extent than Atlantic Canada because of access to natural gas and inexpensive electricity, much of the latter generated from coal-fired thermal facilities and hydroelectric sources. However, in spite of the above energy substitutes, both provinces require relatively large amounts of crude oil because of their high degree of industrialization. This is particularly true of Ontario, which contains the majority of Canada's oil-based petrochemical industry. Ontario consumes one-third of the nation's refined petroleum products.

2.2.5 Regional Considerations - Western Canada

The region comprised of the four westernmost provinces is among the least crude oil dependent of Canada's regions, in absolute terms, due to the relatively small population and industrial base and the variety of energy options, including plentiful, inexpensive supplies of coal, natural gas and electricity generation capacity. British Columbia and Alberta are the largest refined product consumers in the region, at levels more than double those of Saskatchewan and Manitoba. Demand for certain petroleum products such as naphtha specialties, petrochemical feedstocks and still gas in British Columbia and Alberta largely account for this disparity.

2.2.6 Summary

All of Canada, except the Northwest Territories, recorded positive growth rates in refined product consumption in 1987. The lowest demand increase was that of Saskatchewan at 0.5 percent, a reflection of lower economic growth. Ontario, with its continued strong economic performance in 1987, posted a surprisingly low demand increase of 0.5 percent as well. Total demand increases for the other provinces were: Quebec, 1.5 percent; Manitoba, 1.7 percent; Alberta, 3.4 percent; and British Columbia, 6.8 percent. Canada recorded an overall demand increase of 2.9 percent, the first time that the growth rate has been positive since 1979.

2.3 Model Input Assumptions

2.3.1 Macroeconomic Assumptions

Projections of aggregate secondary energy demand were generated by the CERI CREED model. A key exogenous variable within this framework is Real Domestic Product (RDP). Assumed growth rates for regional RDP are shown in Table 2.2.

The Canadian economy was fairly buoyant in 1988, with an expected growth rate of 4.4 percent. An economic downturn is projected for 1989 and the early 1990s, as a result of rising interest rates and an expected recession in the United States. A tight monetary policy accompanied by increased federal taxes is expected to suppress inflation and keep the Canadian dollar high relative to the American dollar. Beyond 1990-1995, Canada is projected to experience fairly strong and stable economic growth.

Alberta continued to recover during 1988 from an economic recession that began in 1986. A temporary rise in oil prices and strengthening gas prices fueled this recovery. In Saskatchewan, the summer drought contributed to a significant fallback in the provincial economy. The expectation of normal weather conditions and continued oil and natural gas market strength should see a strong rebound for Saskatchewan in 1989. However, the grains sector continues to be plagued by chronic global over-supply, and will require significant structural change before permanent recovery, and real price gains, can be projected. In the agricultural sector, livestock prices are currently strong, but are expected to suffer within a few years in keeping with the historical cycle whereby high prices eventually cause excess supply. The forest industries of Saskatchewan and Alberta, although relatively small compared to British Columbia's, have historically been

TABLE 2.2
REAL DOMESTIC PRODUCT ASSUMPTIONS
(average annual percentage change from previous period)

	1988	1989	1990	1995	2000	2005	2010
Atlantic Provinces	4.1	2.3	1.9	1.6	2.0	2.0	2.1
Quebec	4.9	3.0	2.4	1.9	2.4	2.4	2.4
Ontario	4.8	3.0	2.6	2.1	2.6	2.6	2.6
Manitoba	0.4	4.0	2.4	2.0	2.5	2.5	2.5
Saskatchewan	-5.0	6.8	4.7	2.0	2.5	2.5	2.5
Alberta	6.8	2.2	2.9	2.6	3.1	3.1	3.1
British Columbia	4.4	3.4	2.7	2.4	2.9	2.9	2.9
Canada	4.4	3.1	2.7	1.9	2.4	2.6	2.6

SOURCE: Canadian Energy Research Institute.

stable in economic performance and are expected to continue being so. The new Diashowa pulp plant in Northern Alberta should further support the strength of Alberta's forest industry.

British Columbia's economy is expected to continue to strengthen as a result of increased output in its forest and service industries. Both are highly dependent upon the economic performance of the United States, which should remain fairly strong over the 1990s following a brief cooling off period beginning in 1989. The mining industry within British Columbia should remain healthy as international prices for metals and coal continue to be buoyed by increased demand in the industrialized nations.

The provincial economies of Manitoba, Ontario and Quebec are expected to record another year of real economic growth in 1989. Manufacturing and construction industries will continue to enjoy strong demand, particularly in the areas of residential construction and consumer spending on durables and semi-durables. However, while enjoying above average RDP growth rates, those provinces are expected to bear the largest economic growth declines in the early 1990s as their rates move closer to the national level.

The Atlantic provinces are projected to continue at RDP growth rates below the Canadian average. A major consideration here is the potential economic boost that could be provided through the development of the Hibernia and Sable Island offshore petroleum basins. Such development would provide not only significant employment and industrial growth within the region, but also increased energy availability through, in particular, the supply of natural gas to the region.

Prices of most key raw materials are expected to rise in real terms from now to the turn of the century. The economic recession experienced by most industrialized nations in the early 1980s curtailed exploration and development for many commodities, and low prices throughout most of the 1980s caused marginal and inefficient firms to exit from the industry. Those that remain are better poised to deal with reduced demand, but consumers can shortly expect to face certain commodity shortages because initial incremental supply will be unable to keep pace with incremental demand. The resulting price increases should narrow the economic disparities between the provincial economies, particularly between Western and Central Canada. We therefore expect long-term RDP growth rates to range from 1.7 percent for Atlantic Canada to 2.7 percent for British Columbia. This is in

contrast to 1988 RDP growth extremes of 6.8 percent for Alberta to -5.0 percent for Saskatchewan.

The assumptions regarding exchange and inflation rates within CREED are shown in Table 2.3. In the near term, inflation is expected to rise to 5 percent due to rising commodity prices and an expanded money supply to keep interest rates at stable levels. Thereafter, inflation, as measured by the Consumer Price Index, will fall to 4.5 percent as most of Canada experiences a mild recessionary period during the first half of the 1990s. For the remainder of the forecast, inflation is expected to average 5 percent per year.

We have employed an exchange rate forecast for the Canadian dollar in the range of \$0.78-0.81 U.S. The basis for this assumption is the desire of the federal government to keep interest rates at a level conducive to continued economic expansion. Moves by the Bank of Canada during the first half of 1989 to raise interest rates, combined with an influx of foreign direct investment, have caused the price of the Canadian dollar to appreciate to the vicinity of \$0.84 U.S. The long-term exchange rate forecast in this study is based upon our earlier assumptions which, in general, remain valid.

2.3.2 Crude Oil Pricing Assumptions

As a reference crude, we have employed West Texas Intermediate (WTI) at Chicago, Illinois, priced in U.S. dollars. Table 2.4 shows our pricing assumptions for three scenarios—low price, base case and high price. Our analysis concentrates on the base case scenario. The other two price trends indicate the boundaries of what we consider to be plausible, given current economic conditions and what we consider to be likely in the future.

In all likelihood, future oil prices will not follow any smooth price path, let alone that of our base case scenario. First of all, historical prices reveal that since 1973, crude oil price movements have been notoriously volatile.⁵ Second, the power of OPEC and its influence upon future international crude oil prices is uncertain. While the organization no longer determines crude oil prices as strongly as it once did, OPEC is still a key player in international crude oil markets because its members are swing producers—consumers and other producers look to them to balance supply with demand.

The future role of OPEC in international crude oil markets will play a large part in determining crude oil prices. Its current role

TABLE 2.3
INFLATION AND EXCHANGE RATE ASSUMPTIONS

	1988	1989	1990	1991- 1995	1996- 2000	2001- 2005	2006- 2010
Consumer Price Index							
Average Annual Percentage Change	4.5	5.0	5.0	4.5	5.0	5.0	5.0
Average Exchange Rate							
U.S. \$ Per Canadian \$	0.81	0.81	0.81	0.80	0.78	0.78	0.78

SOURCE: Canadian Energy Research Institute.

TABLE 2.4
ALTERNATIVE CRUDE OIL PRICE SCENARIOS^a

	Low Price Case	Base Case	High Price Case
1989	11.18	18.54	19.50
1990	10.00	19.40	20.50
1991	10.50	19.82	21.50
1992	11.00	20.69	22.30
1993	12.01	21.06	23.10
1994	14.29	21.78	24.10
1995	15.56	22.53	25.10
1996	16.90	23.65	26.30
1997	18.30	24.69	27.20
1998	19.81	25.42	28.20
1999	21.32	26.15	29.10
2000	22.96	26.90	30.00
2001	23.83	27.78	31.05
2002	24.74	28.70	32.14
2003	25.68	29.65	33.26
2004	26.65	30.63	34.43
2005	27.59	31.64	35.63
2006	28.55	32.69	36.88
2007	29.55	33.76	38.17
2008	30.59	34.88	39.50

SOURCE: CERI World Oil Market Model, 1988.

^aWTI prices at Chicago, Illinois in real 1986 U.S. dollars per barrel.

is not that of a well defined and cohesive oligopoly, as evidenced by price discounts and overproduction by some members. Yet some unity does still exist, if only in nominal terms. The fact that OPEC is trying to regain some of its former influence in world markets, plus the spectre of its former power, means that OPEC's role cannot be dismissed.

The base case forecast is a "business as usual" scenario, with OPEC continuing to influence world markets in pursuit of gradual volume and real price gains. Should that role change to either extreme, world oil prices would probably oscillate between the low and high price scenarios. As an example, if OPEC were to collapse and each former OPEC member to produce without regard for what other nations are producing, the world would shortly be glutted with cheap oil. As a result, exploration and development of new reserves would be sharply curtailed, as the costs of exploration and development activity would exceed the returns that the oil would bring. Oil prices at this point would be closely aligned with the low price scenario.

Given enough time and constant or rising oil demand, existing oil supplies would be substantially reduced if only because of declining reservoirs. Supplies would tighten and prices would rise correspondingly until they became high enough to provide an incentive to find and develop incremental supplies. This scenario would see crude oil prices in the latter part of the forecast horizon at or near the level indicated by the high price scenario.

The other OPEC extreme reflects what could occur if the members agree to act in concert with regard to prices and production levels, not just in their meetings but in their actions too. The price effects of this would be the same--prices would oscillate in a wave-like pattern between the high and low cases over time, but the initial starting point would be reversed. Both OPEC extremes produce the same overall result, which is a boom and bust phenomenon common to many other commodities.⁶

2.4 Demand Forecast

Crude oil forecasts today tend to be pessimistic about demand growth--in part because energy conservation and interfuel substitution are implicitly present within them. The CREED model and its results are no exception. Average annual oil demand growth is relatively subdued in each of our three price scenarios. The low price case estimates an average increase in crude oil demand of 0.95 percent per year, while that of the high price case is slightly negative. The

base case projection shows Canadian oil demand growing by 0.92 percent per year, on average, over the forecast horizon (see Table 2.5). However, demand does turn down after 2004 and falls through the remainder of the forecast period.

The magnitude of the crude oil demand changes, although small, must be viewed in the context of the demand factors. The CREED and Refined Petroleum Product models assume that all major growth variables increase over time (e.g., number of road vehicles and households). Inverse energy demand variables such as improved mechanical and thermal efficiency are expected to have less of an impact on demand than they have had in the past, as most of their readily attainable exploitation potential has been exhausted. What the CREED results show is that the negative demand factors of price, interfuel substitution and conservation almost totally negate the growth influences in the base case.

Crude oil is not the only energy commodity expected to increase in price, but its increases are large relative to those expected for natural gas and electricity. Therefore oil product demand is dampened by rising prices, by the resulting shifts in demand toward the other two energy forms, and by energy conservation. Average natural gas demand for the base case is predicted to grow at 2.19 percent per year, while that of electricity is estimated to grow at 2.48 percent per year. Smaller price increases, security of supply, convenience and versatility will cause demands for those two energy forms to grow more rapidly than for oil products. Energy conservation will be caused by increasing real prices of both crude oil and natural gas. The CREED results do not exhibit an energy conservation measure per se, but energy consumption per household and per unit RDP are shown. These measurements reflect both energy conservation and capital stock energy efficiency. At the national level, the average forecasted drop in energy intensity per unit of RDP is -0.97 percent per year.

Canadian heavy product demand is expected to exhibit an average growth rate of 0.15 percent per year. Aggregate demand will therefore be relatively static, but its composition and distribution will undergo considerable changes. Of the heavy products, coke, asphalt and lubricants are expected to show increased demand, although this is largely offset by the decline in HFO consumption.

In the middle distillate product range, LFO and kerosene demand declines will be balanced against increases for diesel and jet fuels. Overall demand for this product group is expected to increase by

TABLE 2.5
CANADIAN DEMAND FOR CRUDE OIL,
BASE CASE
 (millions of barrels per year)

Year	Western Canada	Central Canada	Atlantic Canada	Total
1988	178.60	263.06	79.57	521.24
1989	184.96	272.25	83.06	540.28
1990	191.49	282.46	87.03	560.98
1991	200.02	294.82	91.64	586.48
1992	207.96	306.60	95.87	610.43
1993	213.67	315.50	98.26	627.43
1994	217.51	320.76	99.04	637.31
1995	219.83	324.39	99.24	643.46
1996	220.31	327.60	98.73	646.65
1997	221.34	329.61	98.28	649.23
1998	222.04	331.09	97.86	650.99
1999	222.47	331.71	97.26	651.44
2000	223.54	331.13	96.88	651.55
2001	224.89	330.45	96.57	651.90
2002	225.98	330.16	96.55	652.70
2003	226.86	329.63	96.64	653.12
2004	227.13	328.99	96.80	652.91
2005	227.32	327.99	97.03	652.33
2006	225.93	326.85	96.85	649.63
2007	224.62	326.08	96.33	647.03
2008	223.53	324.80	95.66	643.99

SOURCE: Canadian Energy Research Institute.

2.4 percent over the period with increased consumption of transportation fuels more than offsetting the decline in heating fuel sales. The light distillate group is forecast to show a 12.5 percent demand increase over the forecast period. This growth will be solely due to motor gasoline, as demand for aviation gasoline, naphtha specialties and petrochemical feedstock are all expected to fall. Of the gases, both LPG and still gas are predicted to undergo small demand changes, but in the opposite direction. Therefore overall gas demand will only increase 1.8 percent by 2010, relative to our base year of 1985.

The above changes in refined product demand composition will mean that refiners will have to do one or both of two things to extract a greater portion of lighter products--demand lighter crude inputs, or implement refining process changes. Each will reduce the yield of heavy products and increase that of light products. The first option is only realistic if a greater portion of light imported crude is used to dilute the increasingly heavy Canadian crude oil slate, and increased interregional transfers of refined petroleum product occur to balance regional supply and demand. The second alternative, refining process changes, will mean that more widespread and severe coking and "cracking" will have to take place. The latter can be thermal or catalytic, each of which has several specific methods. Regardless of the process change, both cracking and coking achieve higher yields of naphtha and middle distillate products by reducing the production of the heavy by-products (e.g., HFO). In the long run, refinery upgrading would seem to be the preferred alternative.

On a regional basis, Quebec and Saskatchewan are expected to experience reductions in aggregate product demand over the forecast period. Quebec will show the largest decline, with an average drop of -0.56 percent per year. All other CREED regions are forecast to experience demand gains, with that of Alberta being the largest at 0.43 percent per year. The average annual growth rates for British Columbia and Ontario will not be far behind at 0.40 and 0.38 percent, respectively. Ontario's share of Canadian refined product demand is projected to increase from 35 percent in 1985 to 37 percent in 2010, ensuring that it remains the major consuming region.

All sectors and subsectors, with the exception of the transportation subsector, will exhibit declining demands for oil products. The demand gains from transportation are expected to slightly offset the declines of the other (sub) sectors, yielding an overall demand increase. Transportation fuel demand is expected to grow by 19.2 percent over the forecast period, whereas the other refined petroleum

products will experience an aggregate demand decline of 22.4 percent. As a portion of total annual petroleum product demand, the four transportation fuels rise from 64.9 to 73.9 percent over the forecast horizon. The overall demand forecast therefore calls for an increasing concentration of petroleum product consumption in the transportation sector and a significant decline in crude oil dependence among the non-transportation sectors.

Footnotes

¹In addition to energy conservation and fuel switching, a major cause of reduced oil demand was the economic recession during the first half of the 1980s. Petroleum now accounts for 40 percent of Canadian primary energy demand, compared to 55 percent in 1970, according to Energy, Mines and Resources Canada, Energy in Canada (Ottawa: Minister of Supply and Services Canada, 1987), p. 109.

²Domestic sales of refined products in the Northwest Territories dropped by 10.8 percent in 1986, and by 14.6 percent in 1987. Demand increased in the Yukon, with growth rates of 11.6 and 7.6 percent respectively. Of the two areas, the Yukon has a more developed and diversified economy focused on mining, logging and tourism industries. All are present in the Northwest Territories, but to lesser degrees. The latter does, however, have a small oil and gas industry, whereas the Yukon does not. If tourism is excluded, both economies are almost totally dependent upon natural resource extraction and government expenditures.

³A minor amount of natural gas production does occur near Moncton, New Brunswick. Both Nova Scotia and New Brunswick use local coal for electricity generation. The high cost of transporting coal to Newfoundland and Prince Edward Island has discouraged its use in those two provinces.

⁴1987 per capita diesel sales in the other maritime region, British Columbia, were 32.3 percent above the national level.

⁵The posted price of Arabian Light crude at Ras Tanura was constant at \$1.80 (U.S) per barrel from September, 1960 until February, 1971. However, actual market prices were discounted posted prices, so the posted price served as a ceiling. See Gilbert Jenkins, Oil Economists' Handbook (London: Applied Science Publishers Ltd., 1977), p. 130, for a history of crude oil prices from 1860 to 1975.

⁶This phenomenon in economic terms is often called the cobweb theory, and is most commonly observed in agricultural commodities. An example is a farmer who decides this year's production on the basis of last year's prices for the commodity. What he fails to consider is that many of his colleagues are using the same reasoning in their decisions about their production levels of the commodity. The result is either over- or under-production, depending upon the responsiveness of supply and demand to a change in product prices. Market equilibrium may or may not be attained after a couple of years. The term cobweb comes from the graphical representation of this market problem.



Chapter 3

THE WESTERN SEDIMENTARY BASIN

3.1 Canadian Oil Supply Overview

In 1986, the production of crude oil in Canada from all sources was 91 591 thousand cubic metres. In 1987, 95 819 thousand cubic metres were produced while the volume of total established reserves was virtually unchanged at 1492 million cubic metres.¹ The combination of increased production and stable established reserves resulted in a decline in the reserves-to-production ratio (R/P) from 16.3 in 1986 to 15.6 in 1987.

Comparison of total crude oil production to total reserves does not, however, tell the entire story. Table 3.1 shows the low reserves to production ratio of the less expensive, conventional crude oil. The relatively high R/P of the synthetic crude sources and bitumen indicates that there are large quantities of developed, but more expensive, sources of crude in Canada. The token production coming from the frontier regions makes that R/P ratio somewhat misleading. However, there are significant reserves available and additional discovered resources not yet classified as reserves in these regions.

Canada's current supply position does not, at first glance, appear problematic. Canada has considerable reserves of synthetic crude and bitumen, and the future production from frontier sources may be promising. However, our current supplies from conventional sources will exhibit a substantial decline over the next decade if no new major discoveries are made. Similarly, the R/P ratio of over 23 years for pentanes plus may appear comfortable, but the increased demand for diluent to blend with bitumen and heavy oils for pipeline transport has led many observers to question the supply life of this resource and, indeed, to question the viability of future heavy oil shipments from these reserves.

These supply concerns would be unnecessary given a potential for large future discoveries of light/medium crude in Western Canada. However, this does not appear likely. In 1983, the Geological Survey of Canada published an analysis of ultimate potential in Canada, with an update released in 1987 dealing with Western

TABLE 3.1
CANADIAN OIL SUPPLIES
 (thousands of cubic metres)

Conventional Sources	1987 Production	1987 Reserves	Reserves/ Prod. Ratio (years)
Conventional Sources	70 625	765 755	10.84
Synthetic (mined oil sands)	10 423	263 258 ^b	25.26
Bitumen (in situ)	6 731	151 416 ^b	22.49
Frontier	1 567	174 407	111.30 ^a
Pentanes Plus	6 473	138 124	21.34
Total	95 819	1 492 960	15.58

SOURCE: CPA Statistical Handbook and the Canadian Energy Research Institute.

^aFrontier production is so small and inconsistent that this reserves-to-production ratio is not significant.

^bRepresents reserves in relation to operating plants only. Additional reserves are booked as processing facilities become available. The ERCB estimates oil-in-place in the Alberta oil sands and bitumen deposits of 200 billion cubic metres.

Canadian conventional reserves.² The remaining ultimate potential (average expectation) for Western Canada excluding the Northern Territories was 570 million cubic metres or 34 percent of the existing remaining recoverable reserves. This means that even if all of the ultimate potential in Western Canada was discovered, we would have only 23 years of remaining reserves at current production rates. Fortunately, there is significant ultimate potential in other regions of Canada, as shown in Table 3.2.

TABLE 3.2
REMAINING ULTIMATE POTENTIAL OF
CONVENTIONAL LIGHT/MEDIUM CRUDE OIL, 1983

Region	Million Cubic Metres
Western Canada	570
Eastern Basins	167
Beaufort Sea Area	1 347
East Coast Offshore	1 877
Arctic Islands	687
Mainland Territories	88
Other Regions	<u>50</u>
Total	4 786

SOURCE: Geological Survey of Canada.

In addition to the ultimate potential of conventional light/medium oils, Western Canada contains some of the world's largest deposits of tar sands and bitumen. The ERCB estimates that the oil-in-place of these deposits is around 200 billion cubic metres.³

Concerns about the high cost of Canadian oil supply arose in 1986 and again in 1988, when the price of oil became very weak. Weak oil prices effectively eliminate some higher cost sources of supply and reduce the level of exploration for new conventional reserves. Given this situation, Canadians must attempt to optimize investments in their resources in order to efficiently meet national and export demands. Given the current price volatility, it would be very easy to over-invest in high-cost resources and lose the economic benefits and rents of efficient resource allocation.

3.2 Oil Supply Classification and Definitions

"Established reserves" are resources of oil which are known to exist and can be produced given existing technology and economic circumstances.⁴ Canadians can, therefore, be fairly certain that the volume of crude oil classified as established reserves can be produced. However, these sources of oil are not all of the same quality, and Canada's current supply of crude oil may not be entirely compatible with Canadian needs. For example, Canada's large reserves of heavy oil and bitumen may be appropriate for production of heating oils and asphalt but may not be appropriate for production of large quantities of transportation fuels, while upgrading of these heavier products may not be economic at then current world oil prices. As a result, the supply of oil in Canada becomes linked with upgrading or exporting and importing different qualities of crude in order to meet our needs efficiently.

Canada has vast resources of crude oil and, in some cases, the deposits are comparable to the size of resources in the Middle East. Most of these resources are not classified as established reserves because either the production technology does not exist or the costs of extraction are too high, or both. To accommodate the cataloguing of these known but currently uneconomic resources, the oil and gas community in Canada has created another term to classify resources. "Discovered resources" are defined as known deposits of hydrocarbons of sufficient size to be considered "significant", yet which may not be economically produced.⁵ Although this definition was designed for frontier discoveries, it can be applied to many of the tar sands and bitumen/heavy oil resources in Alberta and Saskatchewan.

"Ultimate potential" is the amount of recoverable oil which could ultimately be obtained, under certain economic conditions, from any particular region given an appropriate amount of past and future exploration activity.⁶ Estimates of ultimate potential are undertaken by geologists based upon the volume of sedimentary rock, the geological history of an area, statistical results from drilling activity, and other relevant information. These estimates of ultimate potential provide an upper bound for the projection of future discoveries from a particular horizon or area. "Remaining ultimate potential" is that portion of ultimate potential which has not yet been discovered.

3.3 Conventional Light/Medium Crude Oil

The Western Sedimentary Basin (WSB) contains most of Canada's existing supply of conventional crude oil. In this study, oil supply from the WSB is divided into three quality categories: light/medium, heavy and bitumen. Light/medium and heavy supply sources are estimated using a consistent methodology. Bitumen is categorized and analyzed by technology of production (i.e., in situ or mined) and by upgrading technology (integrated or central).

Light/medium supplies are analyzed below and heavy oil supply is analyzed in Section 3.4. Because of the nature of the exploration and development data in Western Canada, the additions and production of light/medium and heavy oil are forecast together in Section 3.5. Also included in this section is production due to enhanced oil recovery (EOR) projects.

3.3.1 Information Sources

The Western basins are the most mature, the most explored, and the most productive of Canada's existing and potential supply areas. Because of the wealth of information available from this region, estimates of existing reserves, future potential, and likely productive capacity are more easily obtained. Institutions such as the Energy Resources Conservation Board (ERCB) have provided accurate information on existing reserves, and the Canadian Geological Survey (CGS) have made reasonable estimates of ultimate potential. Data on existing reserves are also available from the Canadian Petroleum Association (CPA) on a consistent basis across regions and provinces. Using the CPA data, consistent statistical estimates of future supply can be designed and implemented. Each provincial government in turn produces its own estimates of established reserves and existing productive capacity. It should be noted that these estimates are not always consistent with those of the Canadian Petroleum Association.

3.3.2 Current Sources of Supply from Western Canada

Western Canada's current oil supply comes from several different sources, each with different oil qualities, different production technologies, different resource bases and different reserves. The current production comes from the established reserves in each of these categories. A summary of established reserves in Western Canada is provided in Table 3.3.

TABLE 3.3
ESTABLISHED RESERVES OF CRUDE OIL
IN WESTERN CANADA
 (thousands of cubic metres)

Region	1986	1987
Alberta		
Conventional	632 743	631 315
Oil Sands	260 821	253 258
Bitumen	<u>147 760</u>	<u>151 416</u>
Total	1 041 324	1 045 989
Saskatchewan	106 296	106 146
Manitoba	10 522	10 485
British Columbia	<u>18 500</u>	<u>17 013</u>
TOTAL	1 176 642	1 179 633
Total Pentanes Plus	<u>120 077</u>	<u>119 549</u>
Total Western Canadian Established Reserves	1 296 719	1 299 182

SOURCE: CPA Statistical Handbook.

3.3.3 Specific Methodology

The aggregate nature of this study necessitates the use of fairly simple forecasting methods which do not make thorough use of the wealth of data available on the WSB. CERI recently published a study entitled "An Evaluation of Crude Oil Supply in Saskatchewan,"⁷ which made use of advancements in geological analysis of ultimate potential and a large existing data base in order to provide a better measurement of future supplies of oil from Saskatchewan. That methodology, while appropriate to a broader analysis of hydrocarbon supply, is much too cumbersome to be of practical use in this study.

Instead, estimates of supplies of light/medium crude from future discoveries in all of Western Canada are generated using an historical statistical analysis based upon a fairly straightforward methodology. The methodology chosen does have an important advantage over a simple trend analysis, in that ultimate potential is used as a limit on cumulative discoveries. Actual discoveries are assumed to approach ultimate potential in a nonlinear fashion, such that more effort is required to find and develop the final reserves. This methodology is discussed in more detail in Appendix B.

3.3.4 Data Selection

The data inputs required to estimate the forecast equation include an historical series of cumulative reserves discovered in Western Canada, the number of exploratory wells (or the number of exploratory metres) drilled, and an estimate of the ultimate potential of the region.

Since each provincial government produces its own reserves statistics independently, usually employing different methodologies and assumptions, we felt that it would be more efficient and consistent to use the data series generated by the CPA. Given the differences in estimates between the CPA data and the ERCB data, discussed in CERI Research Report No. 86-2, the CPA reserves estimates may provide a higher estimate of oil reserve additions.⁸ This possible bias is tempered with the restriction imposed upon the equation by ultimate potential. As cumulative drilling increases over time and cumulative additions approach the ultimate potential of a region, the marginal increase in reserves declines. Any upward bias in the CPA data on established reserves would simply shift discoveries to the present without affecting the total volume of reserves discovered because the ultimate discoveries remains constant.

Most data for drilling in Western Canada are consistent across sources. Therefore we once again chose to use CPA data. Historical drilling statistics for Western Canada are provided in Table 3.4.

3.3.5 Ultimate Potential

The estimate of ultimate potential is a very important ingredient of this forecasting methodology and must be carefully chosen. The GSC is responsible for making estimates of ultimate potential for Canada by region and by quantity of crude oil. GSC estimates are provided as statistical ranges, rather than point estimates.

A discussion of the statistical methodology used to estimate ultimate potential for light and medium gravity crude oil is provided in the GSC publication 85-02.⁹ For the WSB, the publication presents ultimate potential with high confidence (95 percent) of 460 million cubic metres, a speculative estimate (5 percent confidence level) of 770 million cubic metres and an average expectation of 570 million cubic metres of recoverable reserves. If we use the December 1987 estimate of initial established reserves in Western Canada of 2550 million cubic metres, we find that there may be one quarter to one fifth of the total reserves of light/medium oil yet to be discovered.¹⁰

This raises three additional theoretical points. The first is that these estimates are based upon current recovery factors from light/medium reservoirs. One must be careful not to assume that these recovery factors will remain constant as technology improves. The definition of established reserves was designed to be prudent. It may be accurate to expect future production technology to improve the recovery of both existing reserves/resources and reserves discovered in the future.

The second important point is that it is unlikely that the entire potential reserves will ever be discovered. If the last few pools require a large number of exploratory wells, the cost of discovering these last pools may be prohibitive. Therefore, the actual production expected from these future reserves will be less than the volume of ultimate potential recoverable reserves.

The third point is that the data base used to estimate the ultimate potential reserves includes pool sizes in various stages of possible appreciation. Appreciation due to extensions could play a significant role in future ultimate potential estimates.

TABLE 3.4
WELLS AND METRES DRILLED IN WESTERN CANADA

	Exploratory		Development		Total	
	No.	Metres	No.	Metres	No.	Metres
Cum. to 1947	1 118	900 861	950	1 239 858	2 068	2 140 719
1947	129	125 953	202	160 688	331	286 641
1948	179	208 307	281	340 034	460	548 341
1949	275	352 126	580	669 524	855	1 021 650
1950	311	410 170	859	946 081	1 170	1 356 251
1951	487	652 801	933	1 135 229	1 420	1 788 030
1952	900	1 084 089	1 282	1 571 582	2 182	2 655 671
1953	905	1 157 247	1 334	1 628 611	2 239	2 785 858
1954	928	1 216 705	1 365	1 575 051	2 293	2 791 756
1955	885	1 212 529	2 050	2 663 245	2 935	3 875 774
1956	899	1 342 829	2 383	3 379 146	3 282	4 721 975
1957	1 058	1 516 179	1 942	2 753 686	3 000	4 269 865
1958	849	1 275 048	1 667	2 502 804	2 516	3 777 852
1959	939	1 397 939	1 629	2 476 581	2 568	3 874 520
1960	818	1 335 657	1 718	2 854 036	2 536	4 189 693
1961	769	1 302 665	1 743	2 888 582	2 512	4 191 247
1962	869	1 397 234	1 640	2 563 288	2 509	3 960 522
1963	1 011	1 579 464	1 850	2 751 836	2 861	4 331 300
1964	1 293	1 833 748	2 007	2 910 220	3 300	4 743 968
1965	1 470	2 078 430	2 163	2 894 937	3 633	4 973 367
1966	1 447	2 050 160	1 605	2 143 615	3 052	4 193 775
1967	1 341	1 913 449	1 537	1 959 486	2 878	3 872 935
1968	1 495	2 257 325	1 500	1 886 373	2 995	4 143 698
1969	1 624	2 149 223	1 553	1 886 851	3 177	4 036 074
1970	1 414	1 884 488	1 522	1 610 239	2 936	3 494 727
1971	1 445	1 861 534	1 489	1 579 190	2 934	3 440 724
1972	1 649	2 176 651	1 936	1 968 887	3 585	4 145 538
1973	2 126	2 403 485	2 271	2 465 742	4 397	4 869 227
1974	1 648	1 971 296	2 319	2 237 618	3 967	4 208 914
1975	1 565	1 715 655	2 467	2 315 283	4 032	4 030 938
1976	2 389	2 301 411	3 104	3 021 340	5 493	5 322 751
1977	2 739	2 803 393	3 237	3 238 430	5 976	6 041 823
1978	3 065	3 529 465	3 913	3 751 819	6 978	7 281 284
1979	2 901	4 111 269	4 554	4 463 970	7 455	8 575 239
1980	3 744	5 234 229	5 188	5 138 500	8 932	10 372 729
1981	3 074	4 257 685	3 897	3 810 523	6 971	8 068 208
1982	2 288	3 161 028	4 093	3 963 678	6 381	7 124 706
1983	1 973	2 804 879	4 877	5 153 549	6 850	7 958 428
1984	2 863	3 977 174	6 517	6 567 178	9 380	10 544 352
1985	3 296	4 611 664	8 794	8 596 464	12 090	13 208 128
1986	1 955	2 836 782	3 730	4 347 112	5 685	7 183 894
1987	2 322	3 434 838	4 518	4 959 110	6 840	8 393 948
Total	64 455	85 827 064	103 199	116 969 976	167 654	202 797 040

SOURCE: CPA Statistical Handbook, Section 1, Table 6, May 1986.

NOTE: Project wells included with development on this table.

These issues are important to keep in mind, as they may substantially affect the supply of oil over time. It is impossible, however, to accurately conclude what the net impact of these three factors will be on ultimate potential and on the final volume of established reserves. Therefore, we chose to use the ultimate potential estimates as published. To explicitly account for uncertainty, the three estimates of ultimate potential noted in Table 3.5 were used in our estimations of future conventional crude oil supply.

TABLE 3.5
ESTIMATES OF ULTIMATE POTENTIAL FOR THE
WESTERN SEDIMENTARY BASIN
(millions of cubic metres)

	Low Case	Base Case	High Case
Initial Established Reserves (1986)	2716	2716	2716
Light/Medium Potential (1986)	460	570	770
Heavy Potential (1986)	200	250	300
Total	3376	3536	3786

SOURCE: Geological Survey of Canada and the Canadian Energy Research Institute.

3.4 Heavy Oil Supply

3.4.1 Heavy Oil Reserves

Canada has large reserves of conventional heavy crude oil, located primarily in eastern Alberta and northwestern Saskatchewan. Table 3.6 shows estimates of established reserves of heavy oil in Canada over the period 1981 to 1987. The large adjustment in the heavy reserves booked by the CPA in 1985 resulted from a major re-evaluation of reserves in the Province of Saskatchewan in that year.

TABLE 3.6
HEAVY CRUDE OIL
CANADA
(thousands of cubic metres)

Year	Initial Established Reserves	Change In Initial Established Reserves	Remaining Established Reserves
1981	243 263		93 420
1982	249 003	5 740	89 839
1983	267 256	18 253	97 137
1984	288 128	20 872	108 406
1985	215 288	-72 840	89 164
1986	222 061	6 773	82 935
1987	233 710	11 649	83 551

SOURCE: CPA Statistical Handbook.

For Alberta, the ERCB shows an increase in initial established reserves from 1986 to 1987 of 9 million cubic metres and an increase in remaining established reserves of 1.5 million cubic metres.¹¹ Most of this increase comes from reassessment of initial volumes in place, pool development, reassessment of recovery factors, and enhanced recovery recognition, rather than from discoveries of new pools.

3.4.2 Heavy Oil Additions

Estimates of heavy oil reserves are aggregated with light/medium oil simply because drilling and reserves statistics disaggregated by heavy and light/medium are not available on a consistent basis. Once the total estimate of reserves additions in Western Canada is complete, it is divided into light/medium and heavy according to the proportion of ultimate potential in each case.

3.4.3 Heavy Oil Ultimate Potential

No exhaustive analysis has been performed of heavy oil ultimate potential. The estimates in Table 3.5 have been generated by reviewing internal CERI documents.

3.5 Conventional Oil Production: Light/Medium and Heavy

3.5.1 Western Canadian Light and Heavy Supply

Western Canadian supply costs are based upon expenditures required to find and produce light, medium, and heavy crude oil using conventional means. CERI has analyzed the finding costs of both gas and oil in Western Canada and is currently working on an analysis of replacement costs. These studies are being published separately.^{12, 13}

For the purposes of this study, we estimated the future supply of conventional crudes using reserves-additions methodology. This allowed us to estimate likely reserves discovered under specific price scenarios.

CERI has prepared scenarios for both light/medium and heavy oil supply. These scenarios are based upon projections of reserves likely to be discovered over time. The production profiles from such reserves are direct functions of the established reserves estimates which were generated under the three different price scenarios. The marginal cost of this supply could be calculated by estimating the cost of drilling and other costs associated with generating and producing these new reserves. These costs are not explicitly calculated in the model. The reserves are assumed to be economic and producible at a rate proportionate to the volume of established reserves.

3.5.2 Estimates of Coefficients

Light/medium and heavy oil reserves were grouped together and regressed against aggregate drilling using the methodology described in Appendix B. The use of different ultimate potentials as presented in Table 3.5 created substantial variations in the additions coefficients. These coefficients are also presented in Appendix B.

3.5.3 Forecasting Drilling Activity

Drilling activity varies as a function of available cash flow and of the profits expected by the oil industry. Estimates of drilling activity were formulated using the three price scenarios developed for this study. We simplified the forecast process by using a single price elasticity for drilling activity in Western Canada. This produced a plausible forecast associated with each of our three price forecasts. The base case forecast of drilling activity is shown in Table 3.7.

TABLE 3.7
WESTERN CANADA: FORECAST OF DRILLING
NUMBER OF WELLS

Year	Base Case Forecast
1989	2783
1990	2875
1991	3104
1992	3179
1993	3251
1994	3347
1995	3405
1996	3454
1997	3529
1998	3583
1999	3635
2000	3556

SOURCE: Canadian Energy Research Institute.

3.5.4 Reserves Additions Forecast

Using the above methodology we were able to produce three forecasts of reserves additions for total conventional crude oil in Western Canada. Then, using the percentage of remaining light/medium and heavy ultimate potential, we proportionally divided these reserves into additions of light/medium and additions of heavy as presented in Tables 3.8 and 3.9, respectively.

Reserves additions associated with EOR were calculated as a proportion of the primary additions. These estimates are presented in Tables 3.10 and 3.11 for light/medium and heavy crude oil, respectively. The total conventional crude oil reserves additions forecast is provided in Table 3.12.

3.6 Bitumen Supply

3.6.1 Bitumen

Bitumen resources in Alberta are considered to be huge. The major constraint on this backstop supply is cost. In order to develop supply prices for these reserves we relied upon forecasts by the National Energy Board,¹⁴ reserves calculations by the ERCB, and estimates provided by the ARC.

The reserves additions process described above is not applicable to the analysis of bitumen. Instead, a standard "cost curve" approach was used. In the model, four different sources of bitumen production were included. These were existing in situ production, Cold Lake expansion, Peace River expansion and existing bitumen mining operations (e.g., Syncrude and Suncor production).

3.6.2 Western Canadian Bitumen Supply

The supply of Western Canadian bitumen comes from identifiable projects. Because bitumen does not flow into the well bore without the addition of heat, the extraction process is complex and expensive. The projects require certain economies of scale and special royalty consideration to be economic, and tend to be large scale with considerable lead-time required for planning and construction. Therefore, bitumen production includes a large capital component and a heat generation component. Bitumen is also produced in the extraction stage of the integrated mined oil sands projects.

TABLE 3.8
WESTERN CANADA
ADDITIONS OF CONVENTIONAL
LIGHT/MEDIUM CRUDE OIL RESERVES
 (thousands of cubic metres)

Year	Low Case	Base Case	High Case
1989	10 776	15 273	17 649
1990	9 803	15 256	17 786
1991	9 839	15 771	18 765
1992	9 965	15 652	18 627
1993	10 717	15 247	18 436
1994	11 568	15 168	18 496
1995	11 696	14 881	18 294
1996	11 740	14 677	18 112
1997	11 850	14 530	17 914
1998	11 909	14 046	17 721
1999	11 931	13 857	17 320
2000	11 376	12 965	16 350
2001	11 176	12 743	16 180
2002	10 975	12 522	16 006
2003	10 771	12 298	15 822
2004	10 562	12 071	15 636
2005	10 335	11 840	15 440
2006	10 104	11 608	15 239
2007	9 872	11 369	15 031
2008	9 639	11 130	14 814

SOURCE: Canadian Energy Research Institute.

TABLE 3.9
WESTERN CANADA
ADDITIONS OF CONVENTIONAL
HEAVY CRUDE OIL RESERVES
 (thousands of cubic metres)

Year	Low Case	Base Case	High Case
1989	4 684	6 696	6 873
1990	4 261	6 688	6 927
1991	4 277	6 914	7 308
1992	4 332	6 862	7 254
1993	4 659	6 684	7 180
1994	5 029	6 650	7 203
1995	5 084	6 524	7 125
1996	5 103	6 435	7 054
1997	5 151	6 370	6 977
1998	5 177	6 158	6 901
1999	5 186	6 075	6 745
2000	4 945	5 684	6 368
2001	4 858	5 587	6 301
2002	4 771	5 490	6 233
2003	4 682	5 392	6 162
2004	4 591	5 292	6 089
2005	4 493	5 191	6 013
2006	4 392	5 089	5 935
2007	4 291	4 984	5 854
2008	4 190	4 880	5 769

SOURCE: Canadian Energy Research Institute.

TABLE 3.10
WESTERN CANADA
EOR ADDITIONS OF CONVENTIONAL
LIGHT/MEDIUM CRUDE OIL RESERVES
 (thousands of cubic metres)

Year	Low Case	Base Case	High Case
1989	2 155	7 636	15 002
1990	1 960	7 628	15 118
1991	1 967	7 885	15 950
1992	1 993	7 826	15 833
1993	2 143	7 623	15 671
1994	2 313	7 584	15 722
1995	2 339	7 440	15 550
1996	2 348	7 338	15 395
1997	2 370	7 265	15 227
1998	2 381	7 023	15 063
1999	2 386	6 928	14 722
2000	2 275	6 482	13 898
2001	2 235	6 371	13 753
2002	2 195	6 261	13 605
2003	2 154	6 149	13 449
2004	2 112	6 035	13 290
2005	2 067	5 920	13 124
2006	2 020	5 804	12 953
2007	1 974	5 684	12 776
2008	1 927	5 565	12 591

SOURCE: Canadian Energy Research Institute.

TABLE 3.11
WESTERN CANADA
EOR ADDITIONS OF CONVENTIONAL
HEAVY CRUDE OIL
 (thousands of cubic metres)

Year	Low Case	Base Case	High Case
1989	936	3 348	5 842
1990	852	3 344	5 888
1991	855	3 457	6 212
1992	866	3 431	6 166
1993	931	3 342	6 103
1994	1 005	3 325	6 123
1995	1 016	3 262	6 056
1996	1 020	3 217	5 996
1997	1 030	3 185	5 930
1998	1 035	3 079	5 866
1999	1 037	3 037	5 733
2000	989	2 842	5 412
2001	971	2 793	5 356
2002	954	2 745	5 298
2003	936	2 696	5 238
2004	918	2 646	5 176
2005	898	2 595	5 111
2006	878	2 544	5 045
2007	858	2 492	4 975
2008	838	2 440	4 904

SOURCE: Canadian Energy Research Institute.

TABLE 3.12

TOTAL ADDITIONS OF CONVENTIONAL CRUDE OIL
RESERVES IN WESTERN CANADA
(thousands of cubic metres)

Year	Low Case	Base Case	High Case
1989	18 554	32 954	45 369
1990	16 878	32 917	45 720
1991	16 940	34 030	48 236
1992	17 157	33 773	47 881
1993	18 452	32 898	47 391
1994	19 918	32 729	47 546
1995	20 138	32 108	47 028
1996	20 213	31 668	46 560
1997	20 403	31 353	46 050
1998	20 503	30 307	45 553
1999	20 541	29 899	44 522
2000	19 587	27 974	42 030
2001	19 242	27 497	41 593
2002	18 897	27 020	41 144
2003	18 545	26 537	40 673
2004	18 185	26 046	40 194
2005	17 795	25 548	39 689
2006	17 395	25 046	39 174
2007	16 995	24 531	38 637
2008	16 595	24 017	38 030

SOURCE: Canadian Energy Research Institute.

The supply estimate of Western Canadian bitumen was developed by focussing upon the costs of existing and future projects. These costs are presented in Table 3.13 without allowance for natural gas feedstock, which is an input cost to the in situ extraction process.

TABLE 3.13
IN SITU BITUMEN SUPPLY COSTS

	Cost Not Including Natural Gas Fuel (\$/bbl)	Established Reserves (MMb)
Esso Cold Lake	11.11	1300
Peace River	14.23	1025
Mined Oil Sands	19.46	8900

SOURCE: Canadian Energy Research Institute

If we include the average yearly cost of natural gas in the calculations, an estimate of the total supply cost of such projects can be obtained. The costs for Esso Cold Lake bitumen were estimated using data from the Esso Cold Lake Submission to the ERCB, January 1985, plus subsequent updates. The costs for Peace River were estimated using the Shell Canada Resources submission to the ERCB, July 1984. Estimates of these costs over time are presented in Table 3.14.

The analytical framework incorporates the potential for additional plants over the forecast horizon. The costs and supply quantities of additional plants are taken from submissions where possible, or are extrapolations from existing information obtained by the ARC. Since the production of bitumen is price sensitive, all production and associated reserves forecasts are dependent upon the specified price assumptions of the model.

3.7 Synthetic Crude

3.7.1 Supplies of Synthetic Crude Oil

An integrated mined oil sands plant extracts bitumen from the oil sands and then upgrades this bitumen into synthetic crude. The production of synthetic crude can, therefore, be divided into three general phases; mining, extraction of bitumen and upgrading.

The cost of producing mined bitumen, included in Table 3.14, is isolated because of the possibility of using a central upgrader for upgrading bitumen from several different sources. The integrated

TABLE 3.14

TOTAL BITUMEN COSTS^a
(including natural gas fuel)

Year	Esso Cold Lake Bitumen (\$/bbl)	Peace River Bitumen (\$/bbl)	Mined Oil Sands (\$/bbl)
1985	13.25	16.87	19.46
1987	13.75	17.49	19.46
1989	14.09	17.91	19.46
1991	14.43	18.34	19.46
1993	14.80	18.79	19.46
1995	15.16	19.25	19.46
1997	15.54	19.71	19.46
1999	15.92	20.18	19.46
2001	16.30	20.65	19.46
2003	16.69	21.13	19.46
2005	17.07	21.60	19.46
2007	17.45	22.07	19.46
2009	17.70	22.38	19.46

SOURCE: Canadian Energy Research Institute.

^aAll costs in constant 1986 Canadian dollars.

TABLE 3.15

OIL SANDS COSTS OF SUPPLY^a

Year	Integrated Mined Oil Sands Costs (\$Cdn. per barrel)
1987	35.53
1989	35.66
1991	35.78
1993	35.92
1995	36.05
1997	36.19
1999	36.33
2001	36.47
2003	36.62
2005	36.75
2007	36.89
2009	36.99

SOURCE: Canadian Energy Research Institute.

^aAll costs in constant 1986 Canadian dollars.

mined oil sands costs are provided in Table 3.15. This calculation is based upon the Syncrude expansion project, which requires \$3.5 billion for initial capital costs and \$630 million in recurring capital costs. Operation costs are expected to be \$16.70 per barrel for production of 86 thousand barrels per day of synthetic crude. This project information was taken from the Syncrude submission to the ERCB on April 27, 1987. The syncrude expansion supply costs were derived using the same methodology as that used by the Alsands project group.

The recently announced OSLO integrated mined oil sands project has a projected production profile of 77,000 barrels per day from a \$4.1 billion capital phase over the 6-year development and a \$40.3 billion dollar expenditure for operating costs over the 35-year operating phase.¹⁵ This study has analyzed both of these types of projects based upon submissions to the ERCB and press releases regarding the terms of agreements. The terms of the agreements are not included in the cost analysis but are discussed and analyzed in Chapter 6.

It is important to note that the economics of the existing integrated mined oil sands technology does not include a charge for cleaning up the massive sludge ponds produced by that technology. These sludge ponds are produced as a result of the hot water/caustic process which discharges a waste liquid in which clay and silt are indefinitely suspended and which contains chemicals which are dangerous to aquatic life. The sludge ponds are enclosed in very large dikes built in close proximity to the Athabasca River.

Estimates of the cost of cleaning up these sludge ponds vary considerably from proposals which maintain it could be done at little or no expense by re-using the sludge in a new extraction process, to proposals involving the construction of costly separate and specialized water treatment plants.¹⁶ Because of the lack of consensus on this issue, no additional charges have been included in this study for clean up of existing technology oil sands plants. Clearly the question of pollutant control will become increasingly important as this massive crude oil resource is more fully developed.

Synthetic crude oil production costs could theoretically be reduced in two general areas, the mining process (i.e., materials handling) and the extraction process. Because of the many years of mining experience, the actual cost of mining is likely to be reduced in new projects. If the extraction process is improved, the costs of environmental clean up could be substantially reduced or eliminated. The

new OSLO project is proposing a further improvement involving a new upgrading technology.¹⁷

3.7.2 Mined Cost Versus Opportunity Cost

Two different costs could be used to determine the cost of producing synthetic crude oil; the market price of the feedstock or the actual cost of mining the feedstock.

There are arguments in favour of either approach. If the market price is used, the value of the feedstock is being included in the cost of the final product. If only the mined cost is included, the project may not be considering all available opportunities for profit.

The cost of upgrader technologies used in the model are presented in Table 3.16. The cost used in the base case run is the market or opportunity cost. Mined cost is used when the market for heavy oil is saturated. Because the opportunity cost is lower than mined cost in early years and exceeds the mined cost in later years, the analysis is more complex. In this case the mined cost could be used until the opportunity cost exceeds the mined cost. Then, the opportunity cost may be used when one is considering the "stand-alone" contribution of the upgrader until such time as the export market is saturated with heavy products.

TABLE 3.16
UPGRADING TECHNOLOGIES

Year	Opportunity Cost ^a		Mined Cost ^a	
	Husky	Bitumen	Husky	Bitumen
1987	31.15	30.08	34.36	37.86
1989	32.19	31.08	35.07	38.07
1991	34.03	32.78	36.30	38.28
1993	35.42	34.03	37.26	38.51
1995	36.97	35.46	38.32	38.74
1997	37.05	35.43	38.51	38.97
1999	37.18	35.45	38.72	39.21
2001	37.59	35.74	39.12	39.44
2003	37.97	35.99	39.50	39.69
2005	38.40	36.29	39.90	39.92
2007	39.62	37.50	40.71	40.16
2009	40.81	38.68	41.49	40.32

SOURCE: Canadian Energy Research Institute.

^aAll costs in constant 1986 Canadian dollars per barrel.

Recently, an agreement to build the Lloydminster upgrader was announced.¹⁸ The project is similar to the "Husky" upgrader incorporated in the model. The Husky upgrader will receive both heavy oil and bitumen and is considered to contain very little technological risk. An alternative bitumen upgrader was also analyzed which would use only bitumen as a feedstock, but which contains some technological risk. The advantage of the bitumen upgrader is that it can use heavy feedstocks which can command higher differentials between the price of the feedstock and the price of the synthetic crude oil product. The advantage of the Husky version is the security of technology and the ability to accept both feedstocks. In the final results, we present only the analysis related to the Husky upgrader scenario.

The cost assumptions which have been included for the Husky upgrader reflect a total spent capital cost of \$1,325 million dollars (over a 4-year period) and production of 46,000 barrels per day of synthetic crude when fully operational.¹⁹ Given different required rates of return, the break even price differential can vary substantially.

Footnotes

¹Canadian Petroleum Association, CPA Statistical Handbook (Calgary: Canadian Petroleum Association, 1987), Section III, Table 7c.

²R. M. Proctor, G. C. Taylor, and J. A. Wade, Oil and Natural Gas Resources of Canada, 1983, prepared for Geological Survey of Canada, Report 83-31 (Ottawa: Supply and Services Canada); J. A. Podruski, J. E. Barclay, R. P. Hamblin, P. J. Lee, K. G. Osadetz, R. M. Proctor, and G. C. Taylor, Conventional Oil Resources of Western Canada, Geological Survey of Canada, Report 87-26 (Ottawa: Supply and Services Canada).

³Alberta Energy Resources Conservation Board, Alberta Reserves of Crude Oil, Oil Sands, Natural Gas, Natural Gas Liquids and Sulfur at December 31, 1986 (Calgary: Energy Resources Conservation Board).

⁴Discovered Resources is referred to in the Canadian Oil and Gas Lands Administration Annual Reports. In the glossary of these publications a definition of "Significant Discovery" is presented.

⁵Significant Discovery: a discovery indicated by the first well on a geological feature that demonstrates the existence of hydrocarbons and suggests the existence of an accumulation that has potential for sustained production. Discovered Resources are essentially made up of Significant Discoveries which have been classified as such by the COGLA group.

⁶Alberta Research Council, Energy Resources Division, Unpublished Description of Internal Energy Models (Edmonton: Alberta Research Council, Oil Sands Research Department, 1988).

⁷James N. Tanner, An Evaluation of Crude Oil Supply in Saskatchewan, Study No. 25 (Calgary: Canadian Energy Research Institute, December 1987).

⁸James N. Tanner, Reserves of Hydrocarbons in Alberta: A Review of Canadian Petroleum Association and Alberta Energy Resources Conservation Board Estimates and Methodology, Research Report No. 86-2 (Calgary: Canadian Energy Research Institute, November 1986).

⁹P. J. Lee, J. A. Podruski, J. E. Barclay, K. G. Osadetz, A. P. Hamblin, G. C. Taylor and R. M. Proctor, Conventional Oil Resources of Western Canada (Light and Medium Gravity), Geological Survey of Canada, A Report to the Petroleum Resource Appraisal Panel, Ottawa December 6, 1985, Department of Energy, Mines and Resources, Calgary.

¹⁰Canadian Petroleum Association, CPA Statistical Handbook (Calgary: Canadian Petroleum Association, 1987).

¹¹Alberta Energy Resources Conservation Board, Alberta Reserves of Crude Oil, Oil Sands Gas, Natural Gas Liquids and Sulphur as at December 31, (Calgary: Energy Resources Conservation Board, 1987, 1986, 1985).

¹²Michele McLachlan, Oil and Gas Finding Costs in Alberta: 1970-1987, CERI Research Report 89-1 (Calgary: Canadian Energy Research Institute, April 1989).

¹³Michele McLachlan, "Oil and Gas Replacement Costs," CERI Study (Calgary: Canadian Energy Research Institute, Forthcoming).

¹⁴National Energy Board, Canadian Energy Supply and Demand 1985 -2005 (Ottawa: Minister of Supply and Services, November 1985).

¹⁵Canada, Government of, and Government of Alberta, Agreement Reached on \$4.1 Billion OSLO Alberta Oil Sands Project, Joint Press Release (Ottawa: Energy, Mines and Resources Canada, September 24, 1988).

¹⁶Oleophilic Sieve Development of Canada Ltd., Billions of Barrels of Sludge, An Alberta Heritage, An Alberta Solution (Edmonton: Oleophilic Sieve Development of Canada Ltd., November 1987).

¹⁷Canada, Government of, and Government of Alberta, Agreement Reached on \$4.1 Billion OSLO Alberta Oil Sands Project, Joint Press Release (Ottawa: Energy, Mines and Resources Canada, September 24, 1988), Document 2, p. 4.

¹⁸Canada, Government of, Government of Alberta and Government of Saskatchewan, Agreement Reached on Building Crude Oil Upgrader in Lloydminster, Joint Press Release (Ottawa: Energy, Mines and Resources Canada, September 2, 1988).

¹⁹Ibid.

Chapter 4

FRONTIER OIL SUPPLY

4.1 East Coast Offshore

4.1.1 Historical Drilling and Discoveries

There has been considerable drilling activity in the East Coast offshore region over the past two decades. Significant discoveries of natural gas were booked as early as 1969 on the Scotian Shelf. However, significant crude oil potential was first realized by the discovery of Hibernia in 1979, followed by several other significant oil discoveries in the North East Grand Banks area.

Most of these discoveries are not classed as established reserves but rather as discovered resources. The Canadian Oil and Gas Lands Administration (COGLA) estimate of discovered resources on the East Coast for 1987 was 203.9 million cubic metres of oil.¹ Table 4.1 shows the activity and total discovered resources for 1987 from the Canadian East Coast Offshore Region.

TABLE 4.1
EAST COAST STATISTICS, 1987

	Newfoundland Offshore	Nova Scotia Offshore
Metres Drilled in 1987	17,486	95.83
Geophysical Km Shot	0	195
Discovered Resources		
Natural Gas (billions of m ³)	146.8	160.9
Crude Oil (millions of m ³)	181.0	22.9

SOURCE: Canadian Oil and Gas Lands Administration, Annual Report 1987.

The major oil discoveries are located offshore Newfoundland in proximity to the Hibernia Field. These discoveries are included in the production forecasts in later chapters.

4.1.2 Production from Discovered Reserves

For the East Coast, production assumptions are based upon publicly available estimates of the capability of existing reserves.² The various production scenarios for existing reserves are provided in Chapter 5, as production timing varies as a function of price. The standard production profile was obtained from the Husky submission to the House of Commons Standing Committee on Energy, December 2, 1986. This scenario begins production at approximately 22,000 barrels of oil per day, increasing to 110,000 barrels of oil per day within the first 2 years. The Husky figures are reproduced in Appendix F.

4.1.3 Forecasting Reserves Additions

Reserves additions have been forecast in a similar manner for all frontier regions. Average additions per well drilled were calculated on an historical basis and declined over the forecast period. These projections are based upon a forecast of the number of wells likely to be drilled given the three different price scenarios assumed. A forecast of East Coast reserves additions is presented in Table 4.2 for the base and high price cases. No reserves additions are discovered under the low price scenario.

4.1.4 Hibernia Costs

The costs for the Hibernia project as projected in our economic analysis are presented in Table 4.3. Capital expenditures are incurred for 6 years prior to initiation of production. Operating costs are proportionate to the level of production.

4.2 Beaufort Sea

4.2.1 Beaufort Sea Activity

Over the past two decades there has been a considerable amount of drilling activity in Northern Canada. The Beaufort Sea has shown tremendous potential as a result of such drilling. Oil was discovered on the Tuktoyaktuk peninsula early in the 1970s followed by many more discoveries of both gas and oil extending well out into the Beaufort Sea, culminating in the 1984 Gulf discovery of the Amauligak field. Suggestions have been made that the threshold reserves level has been reached in the Beaufort Sea region. In the COGLA annual

TABLE 4.2
EAST COAST RESERVES ADDITIONS
(MMb/yr.)

Year	Base Case	High Case
1988	22.1	39.4
1989	21.1	35.9
1990	20.1	32.7
1991	19.2	29.8
1992	18.4	27.2
1993	17.5	24.8
1994	16.7	22.6
1995	16.0	20.6
1996	15.3	18.8
1997	14.6	17.1
1998	13.9	15.6
1999	13.3	14.2
2000	12.7	13.0
2001	12.1	11.8
2002	12.6	10.8
2003	11.0	9.8
2004	10.5	9.0
2005	10.1	8.2

SOURCE: Canadian Energy Research Institute.

TABLE 4.3
HIBERNIA DEVELOPMENT PROJECT COSTS
(millions of \$Cdn.)^a

Year	Capital	Drilling	Operating	Total	Production (MMb/yr)
1	152	0	0	152	0.0
2	480	0	0	480	0.0
3	831	0	0	831	0.0
4	1,308	0	0	1,308	0.0
5	1,206	0	0	1,206	0.0
6	1,168	0	0	1,168	0.0
7		243	113	356	8.0
8		254	430	684	29.2
9		195	621	816	40.2
10		205	652	857	40.2
11		215	685	900	40.2
12		226	719	945	40.2
13		238	755	993	40.2
14		249	793	1,042	40.2
15		262	832	1,094	40.2
16		275	874	1,149	40.2
17		289	918	1,207	40.2
18		303	771	1,074	32.1
19		0	644	644	25.6
20		0	560	560	21.2
21		0	427	427	15.3
22		0	406	406	13.9
23		0	336	336	11.0
24		0	236	236	7.3
25		0	162	162	4.8
26		0	115	115	3.2
Total	5,145	2,954	11,049	19,148	533.0

SOURCE: Canadian Energy Research Institute, and the Alberta Research Council.

^aAll values expressed in current dollars.

report of 1986, 193.2 million cubic metres of oil were designated as discovered resources in the Beaufort Sea area. This estimate was subsequently increased to 253.2 million cubic metres in the 1987 report.³

Two major variables must be assessed in analyzing the possible supplies of oil likely to come from this region. The first is to estimate the level of production that is likely to flow from existing discoveries once development takes place. The second is to estimate a reasonable reserves or resource additions forecast under different price scenarios.

By utilizing available estimates of the size of existing discovered resources in the Beaufort Sea region, CERI, with the assistance of the ARC, generated a likely development profile for existing resources. The production profile is extracted from estimates provided in the Husky Submission to the House of Commons Standing Committee on Energy, December 2, 1986.⁴ This scenario begins with a 6-year lead time for facility and infrastructure development. Production begins at approximately 135,000 barrels of oil per day, rising to 190,000 barrels of oil per day within the first 2 years of production. Production then gradually declines to approximately 20,000 barrels of oil per day after 20 years of operation.

The potential of the Beaufort Sea area is quite large relative to the entire ultimate potential in Canada. CERI designed a relatively simple methodology for forecasting reserves which may be discovered at three different levels of oil prices. This methodology involved calculation of an average finding rate for the area which was assumed to decline over time. The forecast was made by multiplying the average reserves per well times the number of wells expected to be drilled under the three different price forecasts. The resulting forecast of Beaufort reserves additions is provided in Table 4.4.

However, because of the high costs of production in the Beaufort Sea area, these reserves must be contained in a minimum pool size in order to be economic. Using data obtained from independent geologists, a range of pool sizes was developed which is characteristic of the area. Using this method a range of development costs was also obtained for newly discovered reserves in the Beaufort Sea.⁵

TABLE 4.4
BEAUFORT RESERVE ADDITIONS
(MMb/yr.)

Year	Base Case	High Case
1988	53.7	53.7
1989	80.1	93.3
1990	92.7	119.0
1991	105.1	156.8
1992	117.2	218.8
1993	103.2	239.9
1994	89.6	222.8
1995	76.3	206.5
1996	63.2	191.0
1997	50.3	141.1
1998	50.1	104.6
1999	49.9	92.2
2000	37.3	91.4
2001	37.2	79.3
2002	37.0	67.5
2003	24.6	55.9
2004	24.6	44.5
2005	24.5	44.4
2006	24.5	22.1

SOURCE: Canadian Energy Research Institute.

4.3 Arctic Regions

4.3.1 Historical Activity

Exploration in the Arctic Islands has been active over the last two decades. The first significant gas discovery was made in 1969 at Drake Point on Melville Island. Of the few significant oil discoveries made since that time, the Bent Horn discovery in 1974 may prove to be the most economic.⁶

Estimates of further discoveries have also been forecasted for the Arctic Islands and included in our model inputs. These forecasts are included in Table 4.5.

4.4 Frontier Sources of Supply

The frontier sources included in the current modelling system are the Hibernia project, other East Coast offshore production and the Beaufort Sea reserves. The high costs of Arctic region oil production and transportation do not allow this resource an economic window within the time frame of this analysis.

Beaufort costs were obtained from the Husky submission to the House of Commons Standing Committee on Energy and from conversations with individual experts. These costs represent the costs of developing and producing the reserves associated with the Amauligak field⁷ and the near-shore Beaufort and MacKenzie Delta fields.

The frontier areas were further divided into several cost steps. The first cost step relates to reserves already discovered for which proposals have been made. The costs of developing such reserves were extracted from available estimates. Other cost steps relate to extensions and future discoveries for which no independent estimates are available.

The first cost step for the Beaufort Sea area involves producing a reserve of 600 to 650 million barrels. Initial capital costs are expected to be \$4 billion. Another \$2 billion is included in Husky's submission to allow for other regional sources, amounting to another 250 million barrels. Transportation to Edmonton is estimated to be \$8 per barrel and the initial production per year follows the Amauligak production profile presented in the Husky submission to the Common Energy Committee in December 1986.⁸

TABLE 4.5
ARCTIC RESERVE ADDITIONS
(million cubic metres)

Year	Base Case	High Case
1987	2.00	3.98
1988	1.99	3.93
1989	1.98	3.89
1990	1.97	3.84
1991	1.96	3.79
1992	1.95	3.75
1993	1.93	3.70
1994	1.92	3.65
1995	1.91	3.61
1996	1.90	3.57
1997	1.89	3.52
1998	1.88	3.48
1999	1.86	3.44
2000	1.85	3.40
2001	1.84	3.35
2002	1.83	3.31
2003	1.82	3.27
2004	1.81	3.23
2005	1.80	3.19
2006	1.79	3.15

SOURCE: Canadian Energy Research Institute.

Husky Oil outlined the various per barrel cost components of Beaufort production as follows:

Average Capital Cost	\$ 6.35
Average Operating Cost	4.85
Increment	6.80
Pipeline Tariff	<u>2.50</u>
Total	<u>\$20.50</u>

The Hibernia costs were obtained through environmental impact statements and other public documents associated with the proposed project.⁹ Again, the first cost step in Hibernia is associated with already discovered resources where the exploration costs are assumed to be sunk costs.

The costs of Hibernia in the ALF01 model are: capital cost of \$4.212 billion; additional drilling of \$1.639 billion; and operation costs over a 26-year period of \$5.445 billion. Total production from the project is estimated to be 533 million barrels.

The per barrel production costs, net of sunk costs, are expected to be as follows:

Capital	\$ 7.90
Drilling	3.07
Operating	<u>10.22</u>
Total	<u>\$21.20</u>

The Hibernia agreement struck in the Fall of 1988 introduced additional fiscal variables to the cost profile for this project. These are analyzed and discussed in Chapter 6.

Footnotes

¹Canada, Energy Mines and Resources Canada, The Canadian Oil and Gas Lands Administration Annual Report, 1984, 1985, 1986 and 1987 (Ottawa, Ontario: Minister of Supply and Services, 1984 - 1987).

²Canada, Government of, and Government of Newfoundland, Hibernia to Proceed, Statement of Principles, Joint Press Release (Ottawa, Ontario: Energy, Mines and Resources Canada, July 18, 1988).

³*Ibid.*, p. 4.

⁴Husky Oil Ltd., "Submission to the House of Commons Standing Committee on Energy, Mines and Resources" (Calgary, Alberta: Husky Oil Ltd., December 2, 1986), Figure 7.

⁵Recently the Institute for Sedimentary and Petroleum Geology has classified the ultimate potential of this region into four categories which are related to the expected costs of production, among other things. See Oilweek, "Arctic is Still a 'Crown Jewel'", October 17, 1988, p. 6.

⁶Canada, Indian and Northern Affairs, Oil and Gas Statistical Report No. 3, 1920 - 1981: North of 60 (Ottawa, Ontario: Indian and Northern Affairs, 1984).

⁷Husky Oil Ltd., Submission to the House of Commons Standing Committee on Energy, Mines and Resources (Calgary, Alberta: Husky Oil Ltd., December 2, 1986), p. 10, Table 1.

⁸*Ibid.*, Appendix, Figure 7.

⁹Mobil Oil Canada Ltd., Environmental Impact Statement: Hibernia Project (Calgary, Alberta: Mobil Oil Canada Ltd., August 1985).

Chapter 5

SUPPLY/DEMAND BALANCE

5.1 Model Results

Given the recent fluctuations in world oil prices, it is difficult to have confidence in any one oil price forecast. A balanced policy evaluation must include several price scenarios, not only to measure likely changes in demand and supply, but also to test the price risk of various projects. To perform initial tests we chose three different world oil price scenarios and two different assumptions regarding industrial behaviour. Three additional cases were also developed, analyzing the recently announced megaprojects.

In this chapter, we focus on the economics of Canadian oil supply. It is our objective to identify efficient uses of Canada's petroleum resources, given stand-alone projects. The analysis of government incentives and megaproject encouragement is discussed in Chapter 6. Four different cases are presented in this chapter; the low, base and high crude oil price cases, and a variation of the base case assuming perfect foresight on the part of the project developers. Three additional cases are discussed in Chapter 6.

5.1.1 Price Forecasts

The world oil price forecasts utilized in the analysis attempt to cover a low or competitive market case, a base case and a high price case. The low case is designed to reflect the potential downside price risk associated with a competitive world oil market. This case should be taken very seriously; the experiences of 1986 and 1988 have demonstrated the ability of OPEC, through action or inaction, to lower prices even more rapidly than they rose in the 1970s.

The base case scenario extends the existing oil market structure and the existing political realities out into the future, with no major changes other than general resource depletion and consumption of world oil reserves. The high case is designed to identify the possible technologies which the Canadian oil industry could bring into production, if world oil prices rose to sufficiently high levels. This high price case is useful in the ranking of marginal sources of oil supply in

Canada. A summary of the three price scenarios was presented in Chapter 2, and further detail is provided in Appendix H.

5.1.2 Industrial Behaviour

Two different assumptions regarding the decision criterion used by company management were compared. The two criterion are labelled "perfect foresight" and "prudent industrial behaviour." Perfect foresight means that owners in the resource industry are able to perfectly predict future prices and costs of world oil supply. In these circumstances, the companies can efficiently pre-build and operate projects so as to optimize the profits. "Prudent industrial behaviour" assumes that an owner will only choose to develop a particular project when the price of crude oil is at least equal to the per barrel cost of the project. Both assumptions are realistic, with the latter representing a risk averse investor and the former providing a test of what the optimal timing of projects might be.

5.2 Analysis of Production Scenarios

5.2.1 Western Canadian Light Crude Oil Production

The production of light crude oil is determined by the forecast of production from existing reserves plus production from reserves likely to be found in the future. Reserves forecasting techniques were reviewed in Chapters 3 and 4. In order to forecast the production of Western Canadian light crude oil, a reserves-based average production profile was obtained with assistance from the ERCB. This production profile was applied to the reserves generated in each price case.

The decline rates in these production profiles are significant, and demonstrate the view that new sources of oil must be developed if Canada is to maintain its current level of internal petroleum supplies. However, it is important to note that over the past few years the rate of decline of production has not been as rapid as expected.¹ Production levels have been maintained by new discoveries and by technological and recovery advancements. The resilience of Canada's established reserves is some cause for optimism and may affect future estimates of the ultimate potential of the Western Sedimentary Basin. This resilience is analysed in the current study by varying the ultimate recoverable potential estimates used in the model. By doing so, the final results will more adequately cover the possible range of discoveries of future productive capacity from Western Canada.

The difference between the productive capacity in the Western Sedimentary Basin under the three price scenarios is shown in Table 5.1. The variance between the low and high price cases is approximately 100 million barrels per year. This represents the possible difference in production after 20 years of either very weak or very strong prices. To place this figure in perspective, 100 million barrels per year represents more production than any individual megaproject currently proposed. The significance of maintaining productive capacity in the Western Sedimentary Basin is discussed further in Chapters 6 and 7.

5.2.2 Beaufort Sea Production

The production figures in Table 5.2 represent three different forecasts of production from all sources in the Beaufort Sea area. Production in the low case represents production from currently existing reserves only, as future additions are uneconomic under the low price scenario. Production in the base and high cases represent production both from existing reserves and from future additions.

Production in the prudent industrial behaviour case is assumed to begin 6 years after the decision to produce has been made, to allow sufficient time to build appropriate pipelines, gathering systems and new structures, and to drill development wells. In frontier areas like the Beaufort it is important to note that a threshold level of reserves must be established before the decision to produce takes place. The lower the economic assumptions, the larger the threshold level must be. Under all cases, production from existing reserves in the Beaufort area begins in 2004. Production is accelerated significantly under the base price and high price cases, as price-induced exploration and development drilling prove up additional reserves necessary for increased production.

5.2.3 East Coast Production

Production figures in Table 5.3 were derived by summing our forecasts of production from existing and future reserves from the East Coast. The low case scenario represents production from existing reserves only, as future additions are uneconomic under the low price scenario. Under the low case and prudent industrial behaviour assumptions, production is not forecasted to begin before 2009.

The base case and high case represent production from existing reserves and new additions from projected drilling activity. Under the prudent industrial behaviour assumption, development of

TABLE 5.1
WESTERN CANADIAN LIGHT CRUDE PRODUCTION
 (millions of barrels)

Year	Low Case	Base Case	High Case
1988	352.2	353.4	355.5
1989	322.8	327.3	333.8
1990	295.0	304.4	315.6
1991	271.0	286.0	302.4
1992	249.4	269.9	291.4
1993	232.9	258.2	284.4
1994	213.6	242.8	273.4
1995	198.5	230.5	265.3
1996	187.6	221.7	260.2
1997	176.8	212.6	254.5
1998	168.0	205.0	249.8
1999	160.2	197.7	245.3
2000	152.9	190.8	240.6
2001	145.5	183.3	235.1
2002	138.9	176.6	230.0
2003	133.0	170.5	225.4
2004	127.3	164.4	220.6
2005	122.4	159.4	216.8
2006	118.6	155.2	213.7
2007	114.5	150.8	210.2
2008	110.3	146.4	206.7

SOURCE: Canadian Energy Research Institute.

TABLE 5.2
BEAUFORT SEA PRODUCTION
INDUSTRIAL BEHAVIOUR
 (millions of barrels)

Year	Low Case	Base Case	High Case
1988			
1989			
1990			
1991			
1992			
1993			
1994			
1995			
1996			
1997			
1998			
1999			
2000			
2001			
2002			
2003			
2004	32.0	45.4	45.4
2005	45.1	63.8	63.8
2006	46.3	65.5	155.1
2007	59.3	105.7	191.6
2008	65.0	122.0	194.9

SOURCE: Canadian Energy Research Institute.

TABLE 5.3
EAST COAST PRODUCTION
INDUSTRIAL BEHAVIOUR
(millions of barrels)

Year	Low Case	Base Case	High Case
1990			
1991			
1992			
1993			
1994			
1995			
1996			
1997			
1998			
1999			
2000			
2001			
2002			
2003			
2004			
2005			
2006		13.6	13.6
2007		49.3	49.3
2008	0.0	67.8	67.8

SOURCE: Canadian Energy Research Institute.

reserves is projected to take place once the field is economic; production has a 6-year lag from that original decision point. In both cases, production begins in 2006. Production from new reserves additions is not projected to come onstream prior to 2009.

5.2.4 Production of Synthetic Crude

Production of synthetic crude includes production from existing integrated mined oil sands plants, production from the Co-op Upgrader, production from the Lloydminster Upgrader and production from an additional oil sands facility. In the base case, the Co-op Upgrader is producing at capacity in 1989, the Lloydminster Upgrader starts production in 1998 and the oil sands expansion facility begins production in 2006 (see Table 5.4 and Appendix D.2).

Under the low case price scenario, the Lloydminster Upgrader does not come into production during the forecast period. The oil sands expansion facility is delayed one year, to 2007. The timing of these projects is significant because it represents their relative economic attractiveness at a 12 percent rate of return, in real terms. That is to say, the timing of development is based upon the assumption that these projects be required to survive on a stand-alone basis, competing with other uses of capital without special incentives.

In the high price case, the timing of the Lloydminster upgrader is significantly advanced, with production initiated in 1994 versus 1998 in the base case. The relative timing of the upgrader is dependent not only upon the absolute price forecast for crude oil, but also on the differential between the price of bitumen or heavy oil and that of light oil. Changes in this differential would further postpone or accelerate the economics of an upgrader.

Although an integrated mined oil sands operation contains both the production and upgrading of bitumen, in integrated plants the two processes are considered together. The economic analysis is determined by adding the mined bitumen costs and the upgrading costs as one integrated project. Thus the price differential between bitumen and light oil has no effect upon the economics of an integrated mined oil sands projects.

5.2.5 Production of Heavy Crude

The production of heavy crude in Western Canada was estimated using a similar methodology to that of light crudes. As shown in Table 5.5, in the low price case heavy oil production declines more

TABLE 5.4
SYNTHETIC CRUDE OIL PRODUCTION
 (millions of barrels)

Year	Low Case	Base Case	High Case
1988	77.8	77.8	77.8
1989	91.6	91.6	91.6
1990	94.6	94.6	94.6
1991	94.6	94.6	94.6
1992	96.6	96.6	96.6
1993	96.6	96.6	96.6
1994	96.6	96.6	101.7
1995	96.6	96.6	102.5
1996	96.6	96.6	118.5
1997	96.6	96.6	130.9
1998	96.6	98.8	146.9
1999	96.6	99.4	154.1
2000	93.6	97.7	155.6
2001	89.6	93.7	151.6
2002	80.6	87.8	144.4
2003	71.6	94.8	144.8
2004	71.6	110.8	160.8
2005	77.8	116.9	164.9
2006	71.6	122.5	170.6
2007	77.3	139.6	187.6
2008	94.3	161.5	209.4

SOURCE: Canadian Energy Research Institute.

TABLE 5.5
HEAVY CRUDE OIL PRODUCTION
 (millions of barrels)

Year	Low Case	Base Case	High Case
1988	77.8	78.3	78.9
1989	73.2	75.2	77.0
1990	54.0	73.0	76.1
1991	50.9	70.4	75.0
1992	51.4	69.5	75.5
1993	52.1	68.2	75.6
1994	54.0	66.4	75.1
1995	52.5	66.3	76.2
1996	50.0	64.7	75.7
1997	47.3	62.8	74.8
1998	45.5	61.6	74.6
1999	43.7	60.1	73.9
2000	42.7	59.2	73.8
2001	41.5	58.0	73.2
2002	41.1	57.7	73.4
2003	39.6	56.1	72.3
2004	39.0	55.4	72.1
2005	38.3	54.6	71.7
2006	37.5	53.7	71.2
2007	36.7	52.8	70.7
2008	36.8	52.8	71.0

SOURCE: Canadian Energy Research Institute.

rapidly than does light oil production. In the high price case, heavy oil production remains near capacity levels throughout the forecast period. The greater sensitivity of heavy crude production to price changes, relative to light oil production, is due to the higher costs of heavy oil production and the lower demand for the poorer quality heavy crude.

5.2.6 Production of Bitumen

The production of bitumen in this model structure refers to bitumen that is not utilized in integrated mined oil sand plants. Production in this case is a function of price and project economics, rather than reserves estimates. In the base case, a reserves constraint is effective only because reserves devoted to the specific project begin to decline. Table 5.6 shows the three production scenarios for bitumen under the three price scenarios. It is clear that changes in oil prices have a significant effect on the level of production from Canada's bitumen resources.

The production of bitumen is also provided on a project specific basis (see Appendix D). The categories included are existing bitumen production, Cold Lake expansion and Peace River expansion. In our base case scenario, Peace River production is shut-in in 1989 and 1990 due to low prices. It begins operating again in 1991.² In the low price case, Peace River production is shut-in and does not begin again until 1999, while Cold Lake production is shut-in until 1998. This contrasts with the base case where Cold Lake production is not shut-in at all.

No "mothball costs" are considered in this model. In the case of bitumen projects, mothball costs may force operators to operate a project at a small loss or continue with an unprofitable project with the hope that prices will recover. This delayed response to price movements is not reflected in the analytical framework underlying the study.

5.3 Canadian Crude Oil Supply

5.3.1 Three Price Scenarios

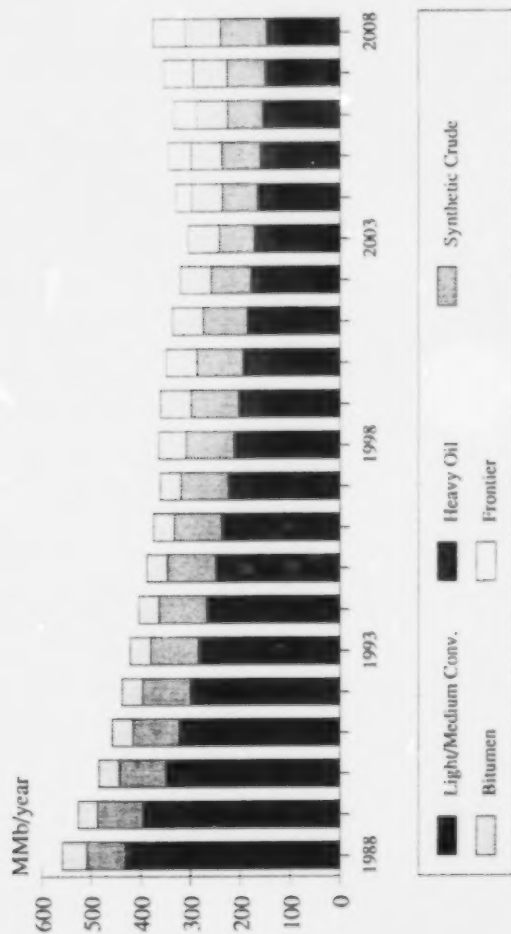
Figure 5.1 shows the forecast of crude oil supplies in Canada under the low price scenario. Of particular note is the decline in production of conventional and heavy crude oil. The only change in the overall decline occurs when frontier sources come on stream in the Beaufort Sea region in 2004. Because of the low level of exploration

TABLE 5.6
BITUMEN PRODUCTION
 (millions of barrels)

Year	Low Case	Base Case	High Case
1988	51.7	51.7	51.7
1989	39.5	46.7	44.1
1990	42.3	53.8	49.3
1991	42.3	61.4	54.7
1992	42.3	62.5	54.4
1993	42.3	62.6	54.9
1994	42.3	62.5	62.5
1995	42.3	62.5	62.5
1996	42.3	72.2	83.9
1997	42.3	73.6	101.4
1998	56.1	73.7	107.8
1999	62.5	73.7	110.7
2000	62.5	73.6	111.0
2001	62.5	75.1	111.4
2002	62.5	77.8	112.7
2003	62.5	91.6	121.0
2004	62.5	104.9	134.0
2005	62.5	110.4	137.6
2006	62.5	111.0	137.6
2007	68.4	108.9	138.3
2008	71.0	101.7	134.7

SOURCE: Canadian Energy Research Institute.

Figure 5.1
Production Summary - All Sources
Low Price Case



SOURCE: CERL

Note: See Appendix "D" for source data

activity under the low price scenario, neither the Western Sedimentary Basin nor the frontiers can maintain Canadian productive capacity. By the end of the forecast period, total Canadian conventional light and heavy crude oil production has fallen by over 65 percent, to 150 million barrels per year.

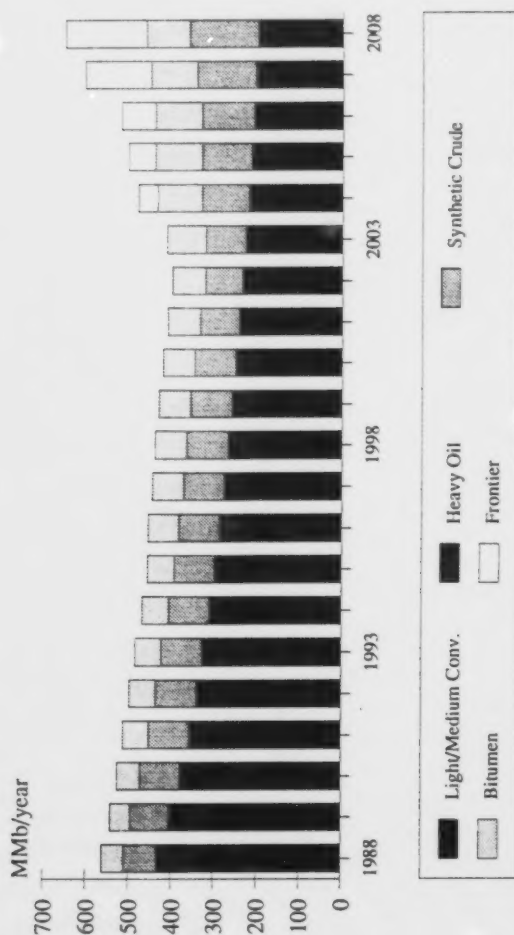
The base case scenario is somewhat more optimistic. Synthetic crude production begins to pick up after the year 2000. Yet the general decline in conventional production is still not balanced by increases in frontier production until very late in the forecast period. Declines in heavy oil production contribute to the decline in over all Canadian production over the period, while increases in bitumen production and synthetic crude production tend to offset the decline. The upward trend in net crude oil imports is reversed in 2003 and import volumes decline significantly over the remainder of the forecast period (see Appendix E.2). The base case production profiles are shown in Figure 5.2.

In the high price case, total Canadian crude oil production bottoms out in 1995 at just over 500 million barrels, and rises significantly through the remainder of the forecast period. Increases in bitumen, frontier and synthetic crude production more than compensate for declines in conventional light and heavy oil production. This indicates the plentiful supply of higher cost Canadian crude oil. The upward trend in net crude oil imports is reversed in 2000 and, on the strength of synthetic and frontier production volumes, Canada becomes a net crude oil exporter in 2007. The high case production profiles are shown in Figure 5.3.

5.3.2 Supply Response to Prices

The figures presented above confirm the price sensitivity of crude oil supply in Canada. Not only are reserves additions sensitive to long-term changes in world oil prices, but this sensitivity could see Canada moving from a totally independent producer of crude oil to a large importer of crude oils within a realistic range of price forecasts. As this analysis demonstrates, fluctuations in crude oil prices can significantly impact the economic performance of certain projects. If prices were to rise, allowing more expensive projects to be initiated, and then subsequently fall substantially, it could jeopardize these very large capital investments and cause significant economic problems within the affected regions of Canada.

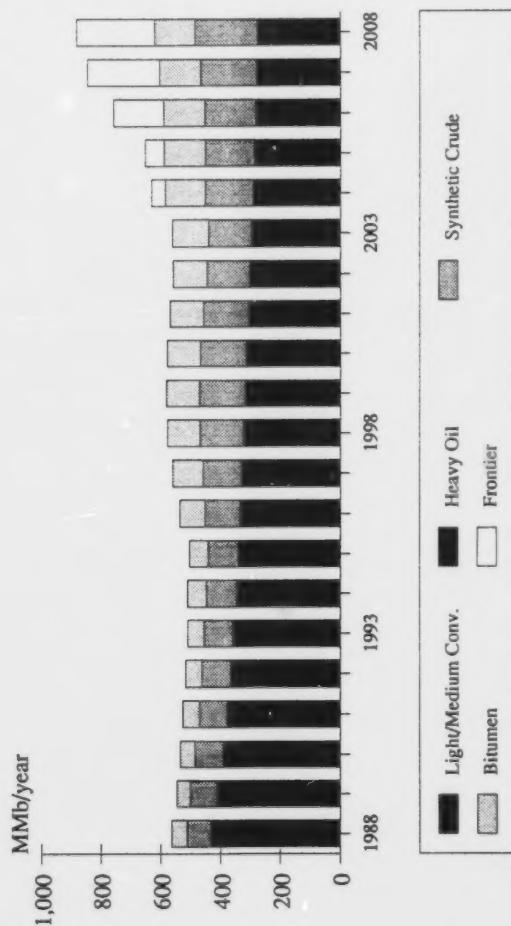
Figure 5.2
Production Summary - All Sources
Base Case



SOURCE: CERI.

Note: See Appendix "D" for source data.

Figure 5.3
Production Summary - All Sources
High Price Case



SOURCE: CERL

Note: See Appendix "D" for source data.

5.4 Canadian Liquid Fuel Balances

Three scenarios are presented here based upon the three world price scenarios and a required real rate of return of 12 percent for projected development. The demand and supply of light crude oil and heavy blends are presented separately to isolate the implications for exports (imports) of heavy and light crude oil supplies.

5.4.1 Light Oil Balance

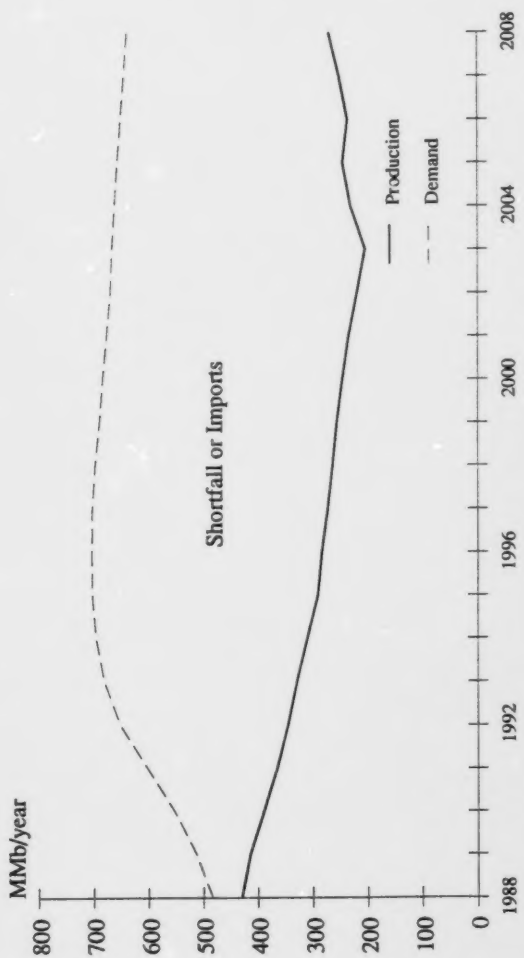
The three scenarios outline vastly different futures for the supply of light crude oil in Canada. While demand is fairly stable across the three scenarios, the supply response to the price declines in the low price scenario place Canada in an increasing deficit position in light oil (see Figure 5.4). Supplies of synthetic crude do not substantially increase over the forecast horizon, and additions from the frontier regions are too small and too late to have much impact. The only consolation is that the lower prices would make such imports of light crude oils relatively less expensive.

In the base case scenario, the decline in Western Sedimentary Basin light oil production is partially made up through increases in synthetic crude production in 2002 and the initiation of frontier production in 2006. Nevertheless, Canada continues to be unable to meet its internal demand for light crude oil products. Figure 5.5 shows the reduced yet continued deficit in light oil under the base case price scenario.

In the high price case, the light crude oil balance is much more optimistic. Due primarily to accelerated production from the frontier, Canada reaches a light crude oil balance by 2006 and retains a surplus throughout the remainder of the forecast period, as shown in Figure 5.6.

A number of important observations can be drawn from this analysis of light crude oil supply/demand balances. First, it is clear that a major, ongoing investment program will be required if Canada is to pursue an objective of self-sufficiency in light crude oil. The targeting of this investment--be it in development of frontier resources, investment in integrated mined oil sands plants and heavy oil upgrading capacity, or more intensive (and extensive) exploration for and development of conventional light crude oil resources in the Western Sedimentary Basin--is clearly secondary to the determination of the objective of self-sufficiency.

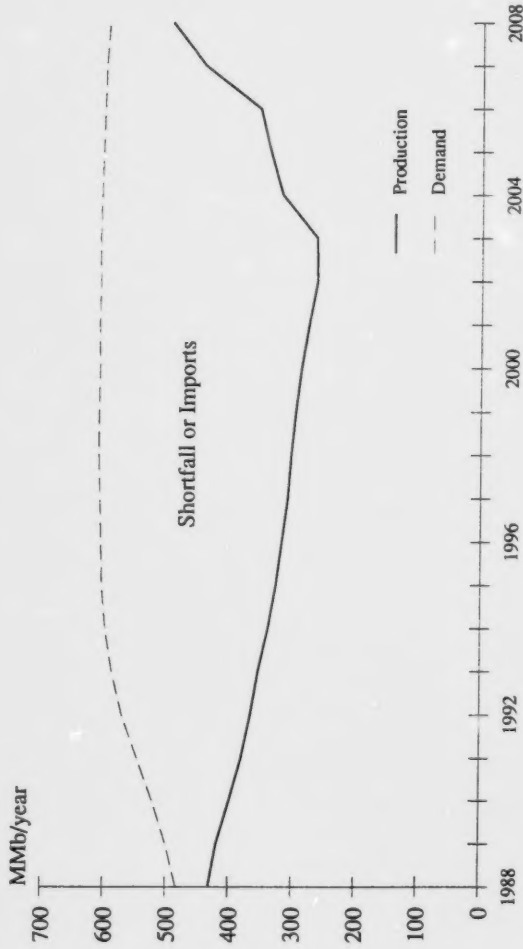
Figure 5.4
Canadian Light Oil Balances
Low Price Case



SOURCE: CERL

Note: See Appendix "E" for source data.

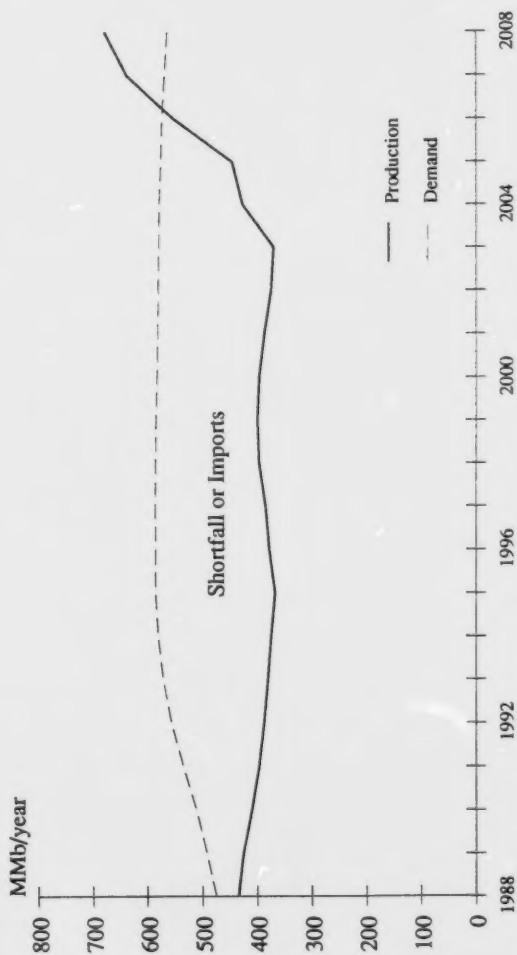
Figure 5.5
Canadian Light Oil Balances
Base Case



SOURCE: CERL.

Note: See Appendix "E" for source data.

Figure 5.6
Canadian Light Oil Balances
High Price Case



SOURCE: CERL

Note: See Appendix "E" for source data.

Research undertaken elsewhere by CERI on likely developments in the world oil market suggests that security of crude oil supply, once a highly emotional issue in Canada, will not be a major factor over the next 10 to 15 years given expectations of global crude oil supply and demand.³ In an environment of significant global surplus crude oil production and capacity, it is critical that Canada consider development policies aimed at increasing domestic light crude oil production in the context of the relative costs and benefits of importing foreign crude oil. In a deregulated market environment, the source of crude oil supplies is clearly secondary to the cost of acquiring those supplies. Due consideration must be given to the import option before Canada commits to further prebuilding of potentially uneconomic production capacity.

A second observation concerns oil price volatility. If price expectations are to be used as a planning guide for energy development in Canada, this volatility must be recognized. Regardless of the degree of market control accorded to a producer organization such as OPEC, price volatility is ultimately driven by supply and demand fundamentals. Actions taken to isolate Canada from these fundamentals, through development of high cost domestic reserves, will ultimately contribute to price volatility and to downward price risk by decreasing the demand for internationally traded crude oil, this at a time of excess market supply.

Gains from such isolation can only be realized if Canada is willing to isolate herself from market-determined pricing. The experience of the 1970s argues strongly against such action. More importantly, Canada would be isolating herself from a low price market environment to support high cost supply development; such action would suggest domestic crude oil prices above internationally traded crude prices, an arrangement clearly less palatable than that of the 1970s.

Clearly, Canada's oil and gas sector cannot abandon projects each time a political or social upheaval causes prices to tumble. Nor can we rush out and invest in massive energy projects the moment there is a temporary production restraint agreement among the Arab states or other OPEC member countries. What is required is an energy development policy that maximizes Canada's access to domestic light crude oil supply, while minimizing our exposure to downward price risk. The decisions taken by the federal and various provincial governments to support the prebuilding of offshore and upgraded light oil production with public sector funds reflects one such strategy, in

which the general public accepts a portion of the price risk in return for greater domestic supply. This strategy is discussed in greater detail in Chapter 6.

5.4.2 Regional Distribution of Light Oil

The regional distribution of oil supplies is important not only to account for the most efficient transportation routes but also to analyze the possible regional economic effects. In the low price scenario, Canadian supplies of light crude are basically used to satisfy the needs of Western Canada and the Southern Ontario refining sector. Crude oil imports to Toronto are initiated in 1991. Oil imports to the Atlantic region are required from the beginning of the forecast period. Both regions continue to import to the end of the period. The regional results are presented in Appendix G.

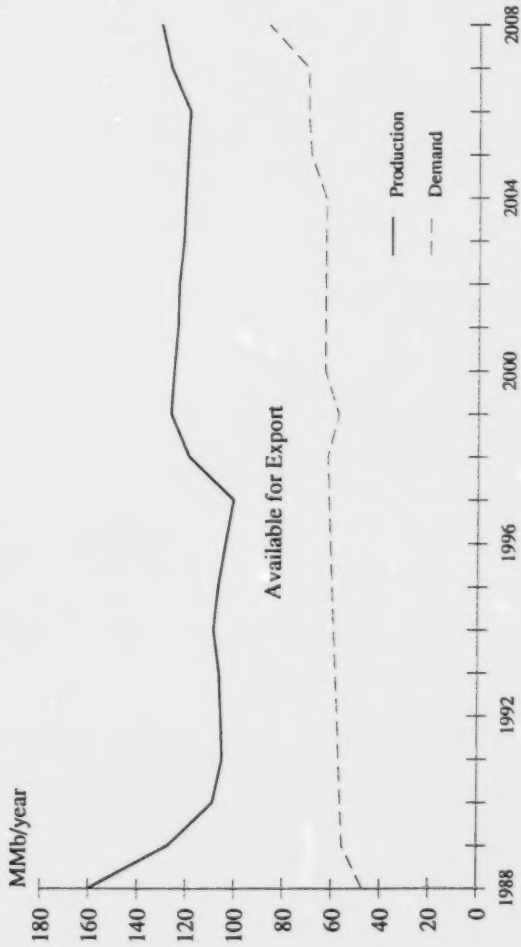
Under the base case, imports of crude to Atlantic Canada are gradually reduced by production from Hibernia, beginning in 2006. Toronto begins importing light oil in 1992 and continues to do so through the remainder of the forecast period. In the high case, imports to Toronto begin in 1994 and are terminated in 2004 as Beaufort crude is brought into the domestic market, while Hibernia production meets a greater share of the Eastern region's oil demand.

5.4.3 Heavy Oil Balances

Under the low price scenario, heavy oil and heavy oil blend continue to be exported by Canada, although in declining quantities (see Figure 5.7). This is due to declining reserves not being replaced by sufficient discoveries, and by higher cost reservoirs being shut-in or not developed.

In the base case and high price cases, domestic upgrading of heavy crudes becomes the dominant feature of the heavy oil market. Demands from the Co-op and Lloydminster upgraders limit the volumes of heavy crude available for export, while the light/heavy crude price differential provides insufficient incentive for a compensating acceleration of heavy oil production. In the base case, Canadian heavy blend volumes move into a near balance by the end of the forecast period, with exports to the U.S. gradually eliminated (see Figure 5.8). Under the high price case, heavy oil exports are eliminated by 2001 and the demand for upgrader feedstock raises concerns over the adequacy of domestic production of heavy oil and bitumen to meet domestic demand (see Figure 5.9).

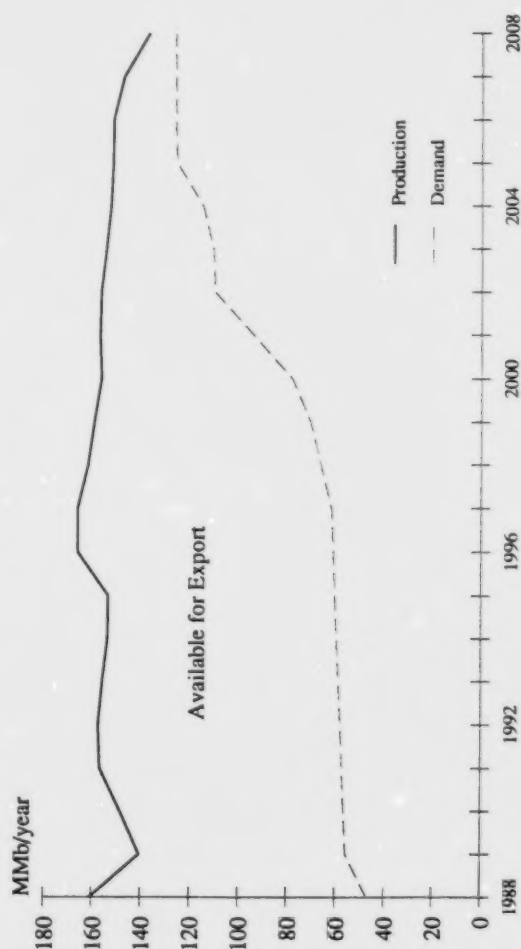
Figure 5.7
Canadian Heavy Blend Balances
Low Price Case



SOURCE: CERL

Note: See Appendix "E" for source data.

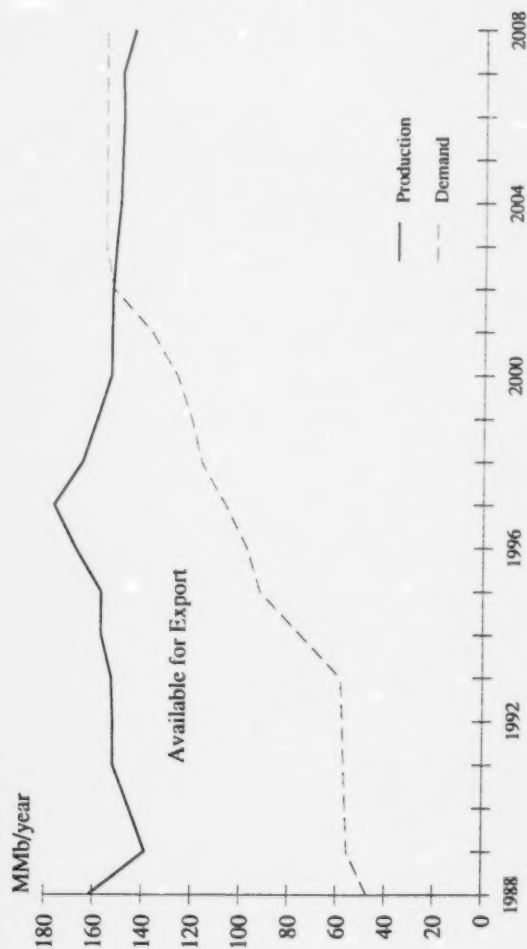
Figure 5.8
Canadian Heavy Blend Balances
Base Case



SOURCE: CERL.

Note: See Appendix "E" for source data.

Figure 5.9
Canadian Heavy Bland Balances
High Price Case



SOURCE: CERL.

Note: See Appendix "E" for source data.

5.4.4 Condensate Balance

The condensate market will be affected by technological advances and variations in the timing of upgrader construction. Diluent is demanded for shipping heavy oil and bitumen to the U.S. market. If the heavy oil and/or bitumen is upgraded rather than exported, the demand for diluent may temporarily decline.

In the low case, the export of heavy products and the demand for diluent are significantly reduced due to much lower production of bitumen and heavy crude oil. Constraints on traditional condensate supply begin in 2002 but are ameliorated by the upgrader demands on heavy oil volumes, also beginning in 2004.

In the base case, the demand for diluent increases in keeping with exports of heavy oil and bitumen. Condensate supply from the natural gas stream begins to decline in 1999, due partially to expansion plans for the petrochemical industry which further increase the demand for condensate and lighter products from the natural gas stream. As this supply source decreases, new sources of supply are sought. The resulting increased condensate price triggers more expensive sources. This situation is similar in the high case scenario, in which significant upgrading capacity is developed in the late 1990s, increasing heavy oil demand for feedstock purposes and reducing to zero the use of feedstock heavy oil as a heavy blend for export. The upgrading of heavy crude postpones by several years the increased demand for diluent.

5.5 Perfect Foresight - Base Case

The perfect foresight case was run using a required real rate of return of 10 percent to reflect the lower project risk associated with price certainty. We compared these results to the base case price run assuming prudent industrial behaviour.

In the perfect foresight case Canada reaches a liquid fuels balance by the year 2004, as shown in Table 5.7. A balance is not achieved in the prudent industrial behaviour case until 2007. This timing differential is due to perfect planning with known future prices. In each major project, the perfect foresight case brings supplies on earlier. The Beaufort Sea production begins in 2000, as opposed to 2004 in the prudent industrial behaviour case. Hibernia begins production in 2004 as opposed to 2006 in the prudent industrial behaviour case. Production from the Lloydminster Upgrader is initiated in 1998

TABLE 5.7
CANADIAN LIQUID FUEL BALANCES
BASE CASE - PERFECT FORESIGHT
(millions of barrels)

Year	Canadian Light Crude Production	Canadian Heavy Blend Production	Canadian Demand For Light Crude	Canadian Demand For Heavy Blend	Net Export of Light Crude	Total Net Exports
1988	431.2	160.7	483.0	47.1	-51.8	61.8
1989	418.9	140.4	500.0	55.6	-81.1	3.7
1990	399.0	148.4	522.0	56.4	-123.0	-31.0
1991	380.6	156.8	547.0	57.2	-166.4	-66.8
1992	366.5	157.5	572.0	57.9	-205.5	-105.9
1993	354.8	155.9	589.0	58.7	-234.2	-137.0
1994	339.4	153.8	600.0	59.5	-260.6	-166.3
1995	327.1	153.6	606.0	60.2	-278.9	-185.5
1996	318.3	166.2	608.0	74.9	-289.7	-198.4
1997	314.9	168.8	610.0	75.6	-295.1	-201.9
1998	334.7	166.8	612.0	90.8	-277.3	-201.3
1999	367.2	161.5	612.0	107.4	-244.8	-190.7
2000	465.2	154.6	611.0	113.3	-145.8	-104.5
2001	527.3	152.7	612.0	113.3	-84.7	-45.3
2002	555.7	152.4	611.0	118.3	-55.3	-21.2
2003	574.4	150.6	612.0	126.4	-37.6	-13.4
2004	602.6	142.0	610.0	126.4	-7.4	8.2
2005	634.4	129.6	608.0	126.4	26.4	29.6
2006	658.7	128.9	606.0	126.4	52.7	55.2
2007	718.7	126.0	604.0	126.4	114.7	114.3
2008	740.6	117.9	599.0	126.4	141.6	133.1

SOURCE: Canadian Energy Research Institute.

but at a higher rate of production than in the prudent industrial behaviour case.

The oil sands proposals are also accelerated. The Syncrude expansion begins in 2000 instead of 2006, while OSLO is advanced considerably to 1997 versus 2009 under the prudent industrial behaviour case. These accelerated starting points are caused by a price forecast which rises over time. If we expect prices to rise, a certain amount of prebuilding is reasonable and probably optimal. The degree to which one can accelerate such projects then depends upon the certainty of future price increases.

Footnotes

¹The National Energy Board and ERCB long-term forecasts of production during the 1985/1986 period tended to be lower than the actuals reported once those years were finished.

²This does not take into consideration "moth ball" costs and is only an indicator of forecasted operational losses. However, it does indicate how close these projects are to a break even situation.

³Appendix D contains detailed production information on different projects.

Chapter 6

ANALYSIS OF MEGAPROJECTS

6.1 The Megaprojects

On July 18, 1988 a joint press release from the Governments of Newfoundland and Canada announced an agreement to develop the Hibernia oil field off the coast of Newfoundland.¹ The cost estimates announced for the project were \$8.5 billion in development and capital costs to produce an average of 110,00 barrels of oil per day. The reserves are estimated to be between 525 and 650 million barrels of recoverable oil.

On September 2, 1988 a joint press release from the Governments of Saskatchewan, Alberta and Canada announced an agreement to build a crude oil upgrader at Lloydminster.² The cost of this project is estimated to be \$1.267 billion dollars. The upgrader is estimated to produce 46,000 barrels of synthetic crude oil per day.

On September 24, 1988 the Governments of Alberta and Canada issued a press release announcing an agreement on the OSLO Alberta Oil Sands Project.³ The initial capital cost of this plant is estimated to be \$4.1 billion dollars. The plant is estimated to produce 77,000 barrels of oil per day.

These three major projects are important to the Canadian crude oil supply/demand balance. The proposed timing of these projects, given current price forecasts, may or may not be economically optimal. In this chapter an analysis of these projects is presented in an effort to further understand their effects upon our supply/demand balance, the efficiency of project investment, and the effects of government subsidies on these projects.

6.2 The Hibernia Project

6.2.1 The Terms of the Agreement

The Hibernia development project involves assistance from both the Canadian and Newfoundland Governments, with the Canadian Government contributing the major subsidy.

The Canadian Government has committed to contribute 25 percent of certain eligible capital costs up to a limit of \$1.04 billion. In addition the Government of Canada will guarantee loans to the project owners up to \$1.66 billion. These loans will be guaranteed in amounts equal to 40 percent of eligible capital costs up to the specified limit.

The Canadian Government also has committed to provide loans to assist in meeting interest payments if the price of oil falls below \$25.00 U.S. per barrel after commencement of production from the project. The overall limit on the interest assistance is \$300 million. An additional \$175 million loan guarantee has been provided as a temporary financing facility.

The Government of Newfoundland and Labrador will provide an exemption on retail sales tax for the capital expenditures related to the project, and reduce the retail sales tax on operations to 4 percent. The Government of Newfoundland and Labrador will also provide \$11 million for a technology transfer fund. Royalty payments will be established between 1 and 5 percent, with the provision that when the oil price is below \$30 per barrel the royalty will be reduced proportionately.

In return for these subsidies and financial guarantees, the project owners commit to use their best efforts to source project related goods and services from Canada, with first consideration to Newfoundlanders. The Government of Canada also retains the right to acquire a 10 percent net profit interest in the project once the repayment of the guaranteed loans has been completed.

6.2.2 The Estimated Employment Impacts

The attachments to the Hibernia Agreement and press release contain estimates of employment generated in both Newfoundland and in all of Canada. The direct employment in the development stage in Newfoundland is expected to be 10,000 person-years. Total direct employment impact for Canada as a whole is expected to be 14,500 person-years, with a further 7000 person-years going to foreign sources. During the production phase an additional 1100 direct permanent jobs are expected in Newfoundland. This employment is likely to have considerable spin-off effects within the regions specified.

6.2.3 The ALF01 Model and Hibernia

As noted in Chapter 5, under the prudent industrial behaviour base case capital expenditures in Hibernia are initiated in 2000, with production beginning in 2006.

Under the recent agreement, the construction phase is to be initiated in 1989 and production is to begin in 1995. This agreement therefore represents an advancement in timing for the Hibernia project of eleven years before it would be profitable on a stand-alone basis. The perfect foresight base case used in the model starts Hibernia production in 1999. The recent agreement represents an advancement of four years from the optimal perfect foresight case, using our base case oil price forecast.

The prudent industrial behaviour case and the perfect foresight case are designed to estimate when Hibernia is likely to be profitable on a stand-alone basis, given the uncertainty of future oil prices. The prudent industrial behaviour case assumes future prices are uncertain and that the project will only be initiated when the participants are comfortable that oil prices are high enough to generate a profit. If prices rose substantially and remained high, the prudent industrial behaviour case would result in production starting too late to generate an optimal profit path.

The perfect foresight case assumes that future prices are known. The project can, therefore, be started at the optimal point. However, the price forecast used in the model may be either optimistic or pessimistic, so this case is determined entirely on the basis of the forecaster's skill. What is of interest is the time difference between the two cases given the same price forecast. This difference of several years indicates that the project contains a substantial amount of price risk. It is this price risk that the government is attempting to reduce through a system of project-specific grants and subsidies.

In order to analyze the effects of subsidies on the Hibernia project, the model was forced to initiate production in 1995. This resulted in an increase in the light crude oil supplies available to the Atlantic Provinces and a consistent decline in Canadian imports of crude oil, relative to the unconstrained base case. The advancement in production also causes a decrease in the rental value of the Hibernia project to the resource owner.

6.2.4 Analysis of Hibernia's Returns on Investment

Under the Hibernia agreement, capital expenditures on the project are initiated in 1989. These expenditures are presented in Appendix F (Table F.2a) together with assumptions concerning drilling expenditures, operating costs and production rates. Table 6.1 outlines average or break-even oil prices which would be required to generate various rates of return. These break-even prices are divided into the various cost categories of capital, development drilling and operating. Since the assessment is undertaken at the date of initiation of production, capital costs increase with an increase in the discount rate. The total price per barrel is the world price, in Canadian and American dollars (in constant 1988 dollars), required to achieve the various rates of return.

If the entire project required no return on capital, the required world price in Canadian dollars would be \$21.20 per barrel. If the required real rate of return was 12 percent, the Canadian price required would be \$37.10 per barrel.

Table 6.2 summarizes the net cash flow analysis of the Hibernia project, including the various forms of government assistance. Given the base case price forecast, the gross cash flow including corporate income taxes and royalties would generate a nominal rate of return of 22.2 percent. The owner's net cash flow, after payment of taxes and royalties, would be 14.5 percent (nominal) over the life of the project.

The return to governments without including royalty and tax revenue would be 3.6 percent (nominal), representing a real loss on public sector investment. Including the royalty payments (net present value of \$263 million) and corporate income tax payments (estimated net present value of \$212 million, depending upon the tax status of the various participants) would increase the nominal internal rate of return to government participation to 22 percent.

These results must be examined in the context of the base case forecast, which calls for significant real crude oil price gains through the late 1990s and into the 21st century. All of the tax revenues generated from the project, and the majority of the potential royalty revenues, are received after the year 2000. If crude oil prices do not rise to the levels indicated, the government sector return from this project will be severely curtailed.

TABLE 6.1a
HIBERNIA COST ANALYSIS

Discount Rate	Discounted Volume (MMb)	Discounted Capital ^a Cost	Discounted Development Drilling ^a	Discounted Operating Costs ^a
0.0%	532.9	4212	1639	5445
5.0%	359.8	4616	1228	3676
7.0%	312.6	4789	1107	3194
10.0%	257.2	5060	959	2628
12.0%	227.9	5249	877	2329

SOURCE: Canadian Energy Research Institute and the Alberta Research Council.

^aMillions of 1988 Canadian dollars.

TABLE 6.1b
COST PER BARREL ANALYSIS

Discount Rate	Capital Cost (\$Cdn.)	Development Drilling Cost (\$Cdn.)	Operating Cost (\$Cdn.)	Total \$Cdn. Cost (\$Cdn.)	Total \$U.S. Cost (\$U.S.)
0.0%	7.90	3.07	10.22	21.20	16.96
5.0	12.83	3.41	10.22	26.46	21.17
7.0	15.32	3.54	10.22	29.08	23.26
10.0	19.68	3.73	10.22	33.62	26.90
12.0	23.03	3.85	10.22	37.10	29.68

SOURCE: Canadian Energy Research Institute and the Alberta Research Council.

TABLE 6.2
HIBERNIA DEVELOPMENT PROJECT SUMMARY
WITH GOVERNMENT ASSISTANCE
(nominal millions of \$Cdn.)

Year	Oil Production (MMb/yr.)	Production Revenues	Owner Gross Cash Flow	Royalty	Income Taxes	Owner Net Cash Flow	Government Share
1989	0.0	0	-60	0	0	-60	-38
1990	0.0	0	-196	0	0	-196	-120
1991	0.0	0	-335	0	0	-335	-211
1992	0.0	0	-552	0	0	-552	-335
1993	0.0	0	-585	0	0	-585	-312
1994	0.0	0	-1341	0	0	-1341	-25
1995	8.0	329	-183	2	0	-185	-31
1996	29.2	1325	409	16	0	393	35
1997	40.2	2006	986	33	0	953	0
1998	40.2	2142	1076	50	0	1026	0
1999	40.2	2365	1103	72	0	931	0
2000	40.2	2567	1108	332	12	764	0
2001	40.2	2796	1231	369	375	487	0
2002	40.2	3048	1367	410	416	541	0
2003	40.2	3322	1973	592	601	780	0
2004	40.2	3621	2402	721	731	710	240
2005	40.2	3946	2660	798	810	786	266
2006	32.1	3441	2291	687	698	677	229
2007	25.6	2982	2289	687	697	676	229
2008	21.2	2693	2087	626	636	617	209
2009	15.3	2057	1595	478	486	471	159
2010	13.9	1964	1522	457	463	450	152
2011	11.0	1636	1268	380	386	375	127
2012	7.3	1150	892	267	271	263	89
2013	4.8	798	619	186	188	183	62
2014	3.2	561	435	131	132	129	44
Nominal Rate of Return Over Project Life			22.2%			14.5%	3.6%

SOURCE: Canadian Energy Research Institute and the Alberta Research Council.

The governments involved in the Hibernia project have acted to reduce the near-term price risk to the industry participants in order to advance the development of domestic sources of crude oil supply. In so doing, they have also accepted a long-term price risk on behalf of all Canadians.

6.3 The Lloydminster Upgrader

6.3.1 Agreement Terms

The Lloydminster Upgrader project involves the Governments of Canada, Saskatchewan, and Alberta, as well as Husky Oil Operations Ltd. Under the agreement, the Government of Canada will contribute 31.67 percent of the capital to the development phase, Alberta will contribute 24.17 percent and Saskatchewan will contribute 17.5 percent. Husky Oil Operations Ltd. will contribute 26.67 percent of the costs, including \$100 million already spent on design work for the project.

The participants will share in the revenues of the project at different rates than their equity contributions. Husky will receive approximately 48.3 percent of the revenue until payout (called the Husky Threshold). Once the Husky Threshold has been reached, 90 percent of the net revenue will be divided according to the percentage equity contribution. The remaining 10 percent is to be divided equally between Canada, Alberta, Saskatchewan and Husky until the separate 5 percent contribution has been paid out. After this final threshold, all project revenues are to be shared according to the original equity contributions of the parties involved.

6.3.2 Employment Estimates

The estimates of employment for the construction and operation phases are divided into regional sectors. Direct employment for the development phase is expected to be 4010 person-years in Alberta, 1640 person-years in Saskatchewan, and 20 person-years for the rest of Canada. For the operation phase, 165 permanent jobs are expected for Alberta and 165 permanent jobs for Saskatchewan. Again, considerable secondary employment gains are expected from this activity.

6.3.3 Model Analysis of the Upgrader

In the prudent industrial behaviour base case, construction of the upgrader is initiated in 1994, with production beginning in 1998 (see Appendix D, Table D.2b). Under the agreement, production from

the upgrader is scheduled to commence in 1992. This is an advancement of 6 years. In the perfect foresight case, production is also scheduled to begin in 1998 but at a significantly higher initial production rate.

The economic implications of advancement of the Lloydminster Upgrader are reflected in the estimated rates of return to the various participants. The ALF01 model requires a real before tax return of 12 percent (16.5 percent nominal) for the project to be economic on a stand-alone basis. The perfect foresight case requires a 10 percent real rate of return. The agreement requires only a 10 percent nominal after tax return in order to reach threshold points for Husky. Since the economics of the upgrader are dependent upon the differential between bitumen and light and heavy oil, several off-model runs have been presented to expand this analysis. Assumptions of these runs for feedstocks and costs and the various prices are included in Appendix F.

A summary of the projected cash flow for each participant is provided in Table 6.3, assuming the base case price scenario and the base case scenario for oil price differentials. The results show a nominal project return for Husky of 19 percent; for Alberta of 13.8 percent; for Saskatchewan of 13.2 percent; and for the Federal government of 13.7 percent. If the downside risk of the oil price forecast is considered, the returns to the various governments are quite low.

A second case was analyzed in which the oil price differential does not increase as rapidly. In this case, as shown in Table 6.4, the Husky nominal return drops to 14.3 percent and the government rates of return drop close to the government cost of capital (the T-Bill rate). This case also assumes the base case price forecast, which embodies considerable downside price risk. However, it is interesting to note that, given a reasonable price forecast, a lower crude price differential does not destroy the economics of the project.

The Lloydminster Upgrader generates lower returns for the government participants, relative to the Hibernia project. Taxes, which will be fairly low in this case, are not added into the governments' cash flow calculations. The price risk for the upgrader comes in two forms. The first is the price differential between light and heavy oils, which is primarily a function of United States demand for heavy crude oil. The second is the absolute level of light oil prices. Both of these future price tracks contain risk and, given the fairly low nominal returns to the government participants, it is questionable whether or

TABLE 6.3

LLOYDMINSTER UPGRADER CASH FLOWS
BASE CASE OIL PRICE AND OIL PRICE DIFFERENTIAL

Year	Husky Cash Flows	Alberta Cash Flows	Saskatchewan Cash Flows	Federal Cash Flows
1989	-25.1	-32.35	-23.43	-42.39
1990	-80.8	-103.99	-75.30	-136.26
1991	-85.3	-109.77	-79.49	-143.83
1992	-46.7	-60.08	-43.51	-78.73
1993	63.2	20.31	12.55	25.69
1994	63.7	23.80	14.70	30.10
1995	61.9	25.49	15.75	32.24
1996	70.7	32.23	19.91	40.76
1997	44.3	32.78	20.25	41.46
1998	63.5	31.88	22.18	41.31
1999	41.1	58.66	24.27	76.87
2000	40.8	60.17	43.57	78.84
2001	43.8	66.30	48.01	86.87
2002	47.1	72.78	52.70	95.36
2003	50.1	78.27	56.68	102.57
2004	55.6	87.77	63.56	115.01
2005	60.8	96.59	69.94	126.56
2006	65.1	103.94	75.27	136.19
2007	67.3	107.74	78.02	141.18
2008	73.7	118.18	85.58	154.86
2009	73.7	118.20	85.58	154.86
2010	73.7	118.20	85.58	154.86
2011	73.7	118.18	85.58	154.86
2012	73.7	118.20	85.58	154.86
2013	73.7	118.20	85.58	154.86
2014	73.7	118.18	85.58	154.86
2015	73.7	118.20	85.58	154.86
2016	73.7	118.20	85.58	154.86
2017	73.7	118.20	85.58	154.86
Internal Rate of Return	19.0%	13.8%	13.2%	13.7%

SOURCE: Canadian Energy Research Institute and Alberta
 Research Council.

TABLE 6.4
LLOYDMINSTER UPGRADER CASH FLOWS
LOW PRICE DIFFERENTIAL CASE
 (millions of \$Cdn.)

Year	Husky Cash Flows	Alberta Cash Flows	Saskatchewan Cash Flows	Federal Cash Flows
1989	-25.1	-32.35	-23.43	-42.39
1990	-80.8	-103.99	-75.30	-136.26
1991	-85.3	-109.77	-79.49	-143.83
1992	-46.7	-60.08	-43.51	-78.73
1993	54.3	16.49	10.19	20.86
1994	54.0	18.45	11.40	23.34
1995	44.5	15.88	9.81	20.09
1996	49.5	20.60	12.72	26.05
1997	49.1	21.70	13.40	27.44
1998	39.8	18.62	12.94	23.55
1999	47.2	23.67	14.62	29.93
2000	43.2	21.98	15.33	28.56
2001	24.3	34.89	25.27	45.72
2002	24.9	36.90	26.72	48.35
2003	24.8	37.55	27.19	49.20
2004	27.1	41.83	30.29	54.82
2005	28.7	44.94	32.54	58.89
2006	29.4	46.27	33.51	60.63
2007	29.8	47.23	33.51	60.63
2008	34.4	54.87	39.74	71.90
2009	34.4	54.87	39.74	71.90
2010	34.4	54.87	39.74	71.90
2011	34.4	54.87	39.74	71.90
2012	34.4	54.87	39.74	71.90
2013	34.4	54.87	39.74	71.90
2014	34.4	54.87	39.74	71.90
2015	34.4	54.87	39.74	71.90
2016	34.4	54.87	39.74	71.90
2017	34.4	54.87	39.74	71.90
Internal Rate of Return	14.3%	8.0%	7.7%	7.9%

SOURCE: Canadian Energy Research Institute and Alberta Research Council.

not the expected government returns are sufficient to justify the future price risk which they are absorbing.

6.4 The OSLO Project

6.4.1 The Agreement

Under the OSLO agreement, the Governments of Alberta and Canada will provide up to \$850 million to the project, termed the OSLO Development Incentive, to be shared equally by the two Governments. This contribution represents 25 percent of the eligible capital costs of OSLO, up to the limit of \$850 million.

A further contribution of \$160 million will be available to the project owners if the actual price of crude oil is equal to or below \$19.00 (U.S.) per barrel or between \$19.00-\$21.00 per barrel, adjusted according to the extent of the price weakness. In addition, the governments will guarantee loans to the project owners to a maximum of \$1.2 billion. The loan guarantees may be drawn down at 37.5 percent of eligible capital costs.

The governments have also provided a temporary financing guarantee to a maximum of \$125 million, and interest assistance to a maximum of \$250 million if prices are below \$25.00 (U.S.) per barrel. In return for these contributions, the governments will receive fees for the guarantees, royalties and net profits associated with the project.

6.4.2 Employment Benefits

The estimates included with the press release materials show 22,000 person-years for the construction phase, and 2,770 permanent jobs in the operations phase. Estimates of natural gas purchases are also included in the employment estimates. However, it is not clear that this is incremental employment.

6.4.3 Model Results for the OSLO Project

In the prudent industrial behaviour base case run, construction on an integrated mined oil sands plant is initiated in 2004, with production beginning in 2010. The OSLO agreement calls for production to begin in 1996. This is a 14-year advancement. In the perfect foresight case, production from the Syncrude expansion is initiated in 2000 and production from a new integrated mined oil sands plant is accelerated to 1997. Thus, given perfect predictive capacity, an oil sands plant would start production one year later than the proposed schedule for OSLO.

CERI has analyzed the likely returns to this project using the base case price forecast. Assuming that the project owners initiate investment in 1990, and projecting the analysis out to the year 2030, the project owners receive an after tax nominal rate of return of 15.5 percent. The governments' net cash flow, estimated separately, yields a nominal return of 7.9 percent. The results of this analysis are presented in Tables 6.5 and 6.6.

By injecting grants, loan guarantees and interest assistance to the project, the government sector is absorbing the risk of lower prices and advancing the timing of the project. The former base case scenario required a 12 percent real return or a 16.5 percent nominal return for the project. With the incentives, the project owners almost maintain this rate of return while the government participants receive a lower expected return, net of royalties and taxes.

The major risk to both government and corporate parties is that of lower oil prices. The returns which would be experienced under a lower price scenario would require the project to be postponed. The break-even oil price of this project was also calculated. At a 0 percent return, the required oil price is \$17.73 (1988 \$Cdn.) per barrel; at 7 percent, \$26.06 per barrel; and at 15 percent the price must be \$42.46 per barrel (see Table 6.7).

As conventional sources of oil decline, more supplies of synthetic crude will be welcome. However, if lower oil prices continue, these supplies may be produced without contribution to the governments' capital investment. The tax payer will have contributed to accelerating a project and subsidizing early synthetic crude consumption, relative to cheaper foreign sources.

6.5 Economic Development Considerations

The economic success of these projects must be measured using public as well as private criteria. The cash flow and economic analysis provided in this and previous Chapters has focussed on the private and public financial returns only. Employment and economic development concerns must be included in a complete socio-economic analysis.

If we use the perfect foresight case as a measure of the financial attractiveness of these projects, the Lloydminster Upgrader would be initiated in 1998, the OSLO or syncrude project in 1997, and the Hibernia project in 1999.

TABLE 6.5
OSLO OIL SANDS PROJECT
OWNERS NET CASH FLOW ANALYSIS
(millions of nominal \$Cdn.)

	GNP Deflator (88=1)	Production (MMb/yr.)	Operating Cost	Owners' Equity	Producer's After Tax Cash Flow	Owners' Net Cash Flow	Royalty
1988	1.000	0	0	0	0	0	0
1989	1.042	0	0	0	0	0	0
1990	1.086	0	0	28	0	-28	0
1991	1.131	0	0	105	0	-105	0
1992	1.179	0	0	207	0	-207	0
1993	1.228	0	0	463	0	-463	0
1994	1.280	0	0	352	0	-352	0
1995	1.334	0	0	426	0	-426	0
1996	1.390	7	500	548	-69	-617	3
1997	1.448	18	521	0	170	170	8
1998	1.509	25	543	0	330	330	24
1999	1.572	28	566	0	345	345	29
2000	1.638	28	655	0	345	345	47
2001	1.707	28	683	0	388	388	51
2002	1.779	28	712	0	426	426	73
2003	1.854	28	741	0	473	473	78
2004	1.931	28	773	0	507	507	105
2005	2.013	28	805	0	554	554	113
2006	2.097	28	839	0	605	605	122
2007	2.185	28	874	0	550	550	368
2008	2.277	28	911	0	599	599	403
2009	2.373	28	949	0	623	623	420
2010	2.472	28	989	0	647	647	437
2011	2.576	28	1030	0	673	673	456
2012	2.684	28	1074	0	611	611	412
2013	2.797	28	1119	0	861	861	589
2014	2.914	28	1166	0	838	838	736
2015	3.037	28	1215	0	872	872	767
2016	3.164	28	1266	0	907	907	799
2017	3.297	28	1319	0	944	944	833
2018	3.436	28	1374	0	982	982	868
2019	3.580	28	1432	0	1022	1022	904
2020	3.730	28	1492	0	1064	1064	942
2021	3.887	28	1555	0	1076	1076	982
2022	4.050	28	1620	0	1121	1121	1023
2023	4.221	28	1688	0	1168	1168	1066
2024	4.398	28	1583	0	1275	1275	1164
2025	4.583	28	1650	0	1329	1329	1213
2026	4.775	28	1719	0	1384	1384	1263
2027	4.976	28	1791	0	1442	1442	1317
2028	5.185	28	1866	0	1503	1503	1372
2029	5.402	28	1945	0	1566	1566	1429
2030	5.629	28	2027	0	1632	1632	1490
Owners' After Tax IRR						15.5%	

SOURCE: Canadian Energy Research Institute and the Alberta Research Council.

TABLE 6.6
OSLO OIL SANDS PROJECT
GOVERNMENT NET CASH FLOW ANALYSIS
(millions of nominal \$Cdn.)

Year	Development Incentive Grant	Indexed Development Incentive Grant	Guaranteed Loan	Interest Assistance	Loan and Interest Assistance Payment	Temporary Financing Facility	Government Share Net Profits Interest	Government Net Cash Flow	Royalties and Taxes
1988	0	0	0	0	0	0	0	0	0
1989	0	0	0	0	0	0	0	0	0
1990	-21	-3	-31	0	0	0	0	-54	-54
1991	-75	-7	-112	-3	0	0	0	-197	-197
1992	-140	-3	-211	-12	0	0	0	-366	-366
1993	-309	0	-463	-30	0	0	0	-801	-801
1994	-235	0	-352	-69	0	0	0	-655	-655
1995	-71	0	-32	-99	0	0	0	-202	-202
1996	0	0	0	-38	0	0	-13	-51	-180
1997	0	0	0	-2	0	-125	32	-95	5
1998	0	0	0	0	0	125	63	188	455
1999				0	197	0	66	262	548
2000				0	194	0	66	260	564
2001				0	191	0	74	265	613
2002				0	189	0	81	270	675
2003				0	194	0	90	284	739
2004				0	213	0	97	309	824
2005				0	233	0	106	339	905
2006				0	256	0	115	371	995
2007				0	280	0	105	385	1202
2008				0	307	0	114	421	1319
2009				0	320	0	119	438	1375
2010				0	333	0	123	456	1434

Continued on Next Page

TABLE 6.6 (Continued)

Year	Development Incentive Grant	Indexed Development Incentive Grant	Guaranteed Loan	Interest Assistance	Loan and Interest Assistance Payment	Government Share				Royalties and Taxes
						Temporary Financing Facility	Net Profits Interest	Government Net Cash Flow		
2011				0	347	0	128	475	1496	
2012				0	614	0	116	730	1649	
2013				0		0	164	164	1494	
2014				0		0	160	160	1616	
2015				0		0	166	166	1685	
2016				0		0	173	173	1757	
2017				0		0	180	180	1832	
2018				0		0	187	187	1911	
2019				0		0	195	195	1992	
2020				0		0	203	203	2077	
2021				0		0	205	205	2197	
2022				0		0	214	214	2290	
2023				0		0	222	222	2386	

SOURCE: Canadian Energy Research Institute and The Alberta Research Council.

TABLE 6.7
OSLO PROJECT
BREAK-EVEN ECONOMICS

Discount Rate	Discounted Capital	Discounted Volume	Operating Cost	Capital Charges	Operating Cost	Total
(%)	(MM 1988 \$Cdn.)	(MMb)	(MM 1988 \$Cdn.)	(1988 \$Cdn./barrel)		
0	3278.72	949.76	13 560	3.45	14.28	17.73
5	3733.55	450.11	6666	8.29	14.81	23.10
7	3931.25	356.56	5362	11.03	15.04	26.06
10	4245.86	265.74	4089	15.98	15.39	31.36
12	4468.21	225.18	3518	19.84	15.62	35.47
15	4821.65	182.04	2908	26.49	15.98	42.46

SOURCES: Canadian Energy Research Institute and the Alberta Research Council.

TABLE 6.8
CANADIAN LIQUID FUEL BALANCES
BASE CASE - MEGAPROJECT INCENTIVES
(millions of barrels)

Year	Canadian Light Crude Production	Canadian Heavy Blend Production	Canadian Demand for Light Crude	Canadian Demand for Heavy Blend	Net Export of Light Crude	Net Export of Total Crude
1988	431.2	160.7	483.0	47.1	-51.8	61.8
1989	418.9	140.4	500.0	55.6	-81.1	3.7
1990	399.0	148.4	522.0	56.4	-123.0	-31.0
1991	390.6	156.8	547.0	57.2	-166.4	-66.8
1992	366.5	157.5	572.0	57.9	-205.5	-106.9
1993	371.6	133.8	589.0	74.7	-217.4	-158.3
1994	346.5	131.7	600.0	75.5	-253.3	-197.1
1995	359.3	131.6	606.0	76.2	-246.7	-191.3
1996	392.0	164.7	608.0	76.9	-216.0	-128.2
1997	413.0	167.9	610.0	77.6	-197.0	-106.7
1998	403.9	166.5	612.0	79.4	-208.1	-121.0
1999	401.7	160.9	612.0	82.9	-210.3	-132.3
2000	409.2	154.1	611.0	86.9	-201.8	-134.6
2001	410.6	152.6	612.0	102.9	-201.4	-151.7
2002	396.5	152.4	611.0	111.1	-214.5	-173.2
2003	381.4	150.6	612.0	111.1	-230.6	-191.1
2004	426.8	142.0	610.0	115.0	-183.2	-156.2
2005	448.5	129.9	608.0	125.8	-159.5	-155.4
2006	440.4	128.9	606.0	126.4	-165.6	-163.1
2007	485.4	126.0	604.0	126.4	-118.6	-119.0
2008	513.7	117.9	599.0	126.4	-85.3	-93.8

SOURCE: Canadian Energy Research Institute.

Comparing the minimum 0 percent returns, the break-even or threshold crude oil price is \$21.20 (Cdn.) per barrel for Hibernia and \$17.73 (Cdn.) per barrel for OSLO. Profitability of the Lloydminster Upgrader is determined by the differential between light and heavier products, rather than the absolute price levels.

Referring to the marginal employment benefits, the Hibernia project generates a major increase in employment in Newfoundland, which is traditionally a high unemployment region. The higher cost of Hibernia can be somewhat balanced in public policy terms, therefore, on the basis of the predicted employment effects. The same conclusion can be applied to Alberta and Saskatchewan given the current unemployment rates in those provinces. The price risk, therefore, must be weighed against the employment benefits.

Another macro-economic consideration is that of balanced development timing. It may be possible that the construction of the Lloydminster upgrader and OSLO at the same time will temporarily strain the construction resources of the northern Alberta economy. Consideration should be given to staging the construction so that a boom-bust cycle is prevented and a more sustainable level of activity is achieved.

6.6 Canadian Supply/Demand: Three Megaprojects

If all three megaprojects are built as proposed they will dramatically change the supply/demand balance in Canada. The ALF01 model was run to determine the effects upon the total Canadian crude oil supply/demand balance using both base case prices and high case prices, and the perfect foresight case.

In the base case shown in Table 6.8, the supply of light crude oil is increased significantly by production from the megaprojects. However, these incremental supplies are still not sufficient to achieve Canadian self-sufficiency in light crude oil.

In the perfect foresight base case, additional oil sands plants are constructed. This has the effect of substantially reducing Canadian imports of light crudes and restores Canada to self-sufficiency in liquid fuels by 2009. These results and those of the high price case are presented in Appendix D.

Footnotes

¹See, Canada, Government of, and Government of Newfoundland, Hibernia to Proceed, Joint Press Release (Ottawa: Energy, Mines and Resources Canada, July 18, 1988); Canada, Government of, Government of Newfoundland, and Government of Labrador, Project Owners: Hibernia Background Papers, Joint Press Release (Ottawa: Energy, Mines and Resources Canada, July 18, 1988).

²Canada, Government of, Government of Alberta, and Government of Saskatchewan, Agreement Reached on Building Crude Oil Upgrader in Lloydminster, Joint Press Release (Ottawa: Energy, Mines and Resources Canada, September 2, 1988).

³Canada, Government of, and Government of Alberta, Agreement Reached on \$4.1 Billion OSLO Alberta Oil Sands Project, Joint Press Release (Ottawa: Energy, Mines and Resources Canada, September 24, 1988).



Chapter 7

CONCLUSIONS AND RECOMMENDATIONS

7.1 The Canadian Supply Dilemma

This study has confirmed the findings of other analyses of Canada's conventional crude oil resources that, under a reasonable forecast of crude oil prices, Canada will face a decline in conventional crude oil production through the 1990s and, of particular concern, a rapidly growing deficit in light crude oil balances. Recent discoveries in British Columbia provide support for the view that there remain significant undiscovered pools of hydrocarbon reserves in the Western Sedimentary Basin which could temporarily delay the decline in light crude oil production. However, it is likely that the costs of finding these resources will increase over time, due partly to the decline in average discovery pool size.

Canada therefore faces a supply dilemma. Should we invest now in development of nonconventional and frontier sources of light crude oil, which will yield predictable volumes of expensive crude oil, or should we postpone development until we are more certain of the medium-term trends in world oil prices? Alternatively, should we refocus energy policy towards more intensive and extensive development of the remaining oil in place in the Western Sedimentary Basin, and towards proving up of the undiscovered resources believed to remain in the Basin?

The major risk factor in this policy decision is the future level of crude oil prices; the costs of an incorrect guess could be substantial. If the development of nonconventional and frontier sources of light crude oil is delayed, we will likely increase our exposure to foreign imports and dependence on foreign oil supplies which could rise in price without notice. Given a policy framework of deregulated domestic energy markets and acceptance of market determined prices, the real cost here would be revenue foregone by not having these projects in place when world oil prices rise sufficiently to justify the internal economics of the projects.

Alternatively, if the development of nonconventional and frontier sources of light crude oil is accelerated in advance of oil prices

sufficiently high to justify the undertaking, Canada risks losing a portion of this investment in the event that world oil prices remain low. To the extent that the public sector becomes involved in the development of these resources, this risk will be borne by all Canadians.

7.2 Private Risk Capital

Private capital, in the normal course of business, is prepared to accept a certain amount of risk. All major oil companies in Canada live with the risk of oil price volatility. The level of risk that each company takes is reflected in its cost of capital. The larger is the risk associated with a given project or activity, the higher is the cost of capital for that activity. Thus, if the potential return to a project is high enough and the risk is diversifiable, private capital may become available.¹

In Chapter 6 of this study, it was shown that the normal rate of return expected from development of Canada's nonconventional and frontier crude oil resources was not available unless these projects were postponed into the late 1990s and early into the next century. This analysis was based on the assumption of acceptable risk for private capital and private sector development. To initiate development at an earlier date would require a reduction in project risk, or an increase in the associated rate of return, to the project developers.

7.3 Government Participation

Governments have the responsibility to fulfill public policy objectives in the most efficient way possible. In the case of the supply and demand of Canadian crude oil, the public policy objectives are numerous. Some of the more important are:

- to ensure adequate, least cost supplies of crude oil products to Canadian consumers;
- to optimize the production and value of indigenous supplies of crude oil; and
- to promote economic activity throughout the various regions of Canada, both with respect to inexpensive sources of energy to industrial consumers and with respect to the value added production and processing of those supplies in Canada.

The decisions of the federal and various provincial governments to participate in the accelerated development of Canada's non-conventional and frontier resources must be assessed in light of these

objectives. In its simplest form, public sector participation in these projects is designed to reduce, or diversify, the risk to private sector capital from development of these resources. Chapter 6 discussed the likely returns to government and industry of public sector participation as a minority partner.

In each situation, there are optimal methods of participating. Loan guarantees, which appear attractive because they do not carry readily apparent direct effects upon government deficits, represent a real financial risk to the taxpayer and must be considered as such. Direct grants are also used extensively in these project agreements. The grant is often made with conditions attached which can have the effect of making the grant into a form of second class equity. However, direct grants must meet the test that they are the most efficient way to achieve the objectives of least cost crude oil supply and creation of regionally sensitive economic activity.

Government equity, whether in the form of loan guarantees with fees, conditional grants, or direct participation, may contribute direct financial returns to the government as well as contributing to potential public policy goals.

According to the results of the base case analysis provided in Chapter 6, each of the megaprojects carries the potential to be profitable for owners and governments alike. Under the high price case, additional nonconventional and frontier projects would likely come on stream based entirely on private sector participation.

According to the internal economics of each project, oil supply from Hibernia is likely to be the most expensive on a per barrel basis, followed by supply from the OSLO integrated mined oil sands plant and then by production from the Lloydminster Upgrader. If crude oil prices remain at current levels in real terms, the losses incurred from development of Hibernia would have to be justified on the basis of economic development in the Atlantic region and reduction of that region's dependence on imported oil. Under the low crude oil price scenario examined in this study, these losses could amount to several billion dollars.

The projected per barrel costs for the OSLO project are not quite as high as those of Hibernia, assuming that a large environmental control or clean up expense is not incurred. Therefore, the downside price risk is not as great for OSLO and, hence, the risk

accepted by government through equity incentives to OSLO is also not as great.

The Lloydminster Upgrader is structured more as a partnership than as a subsidy. The success of the project is dependent upon the light-heavy oil price differential, rather than the absolute level of oil prices, yielding a different risk assessment than for the other projects being considered. This differential is expected to become larger as prices rise, thus making the upgrader profitable. The downside risk of constructing an upgrader can be further diminished by assuming, as in the case of integrated mined oil sands plants, that the upgrader can obtain heavy oil and bitumen at extraction cost rather than opportunity cost. Nevertheless, it is entirely possible that the oil sands plant and the upgrader could become uneconomic if world oil prices remain low. To go ahead with these projects is to believe that oil prices will rise substantially in real terms over the next 20 years.

7.4 Conventional Sources

Megaproject development dominated the focus of oil policy in 1988. The costs of these megaprojects have been discussed in this study from many different angles. An important conclusion arising from the analysis is that these costs are generally higher than the costs of producing conventional light and heavy oil from the Western Sedimentary Basin.

It is likely that there are substantial quantities of conventional oil available from this basin at lower costs than either OSLO or Hibernia. The incentives that may be required to increase conventional production from the Western Sedimentary Basin may not be as simple as megaproject incentives, but they may be more cost effective.

It is a recommendation of this study that conventional sources of light and heavy crude oil, including EOR, be reviewed to determine optimal levels of incentives; that these incentives be designed to promote the extraction of less expensive sources of crude oil before more expensive sources; and that these incentives be designed to maintain the productive capacity of the Western Sedimentary Basin as much as economically possible. Further, such incentives should be based upon a consistent long-term policy rather than a series of short-term band-aid programs.

The potential exists in the conventional areas to continue to contribute significantly to Canadian requirements of light crude oil. Canadian public policy should be directed to optimizing investments in this major resource.

7.5 Back Stop Crude Oil Supplies

Canada has enormous supplies of heavier crude oil products. This resource is only partially accessible under current technology because of the high costs of extraction and processing. A major goal of this study was to investigate just how accessible such supplies are.

The conclusion is that the costs of producing major portions of the bitumen and oil sands deposits are consistent with, or even less expensive than, other major Canadian frontier megaprojects.

It is a recommendation of this paper that if Canada is confronted with a major shortfall of supplies of light crude oil, then careful consideration should be made to environmentally sensitive extraction and upgrading of bitumen and oil sands resources; and that extraction and upgrading research focus on methods which allow smaller incremental capital requirements in order to diminish the risk of volatile world oil prices.

7.6 Beaufort - The Forgotten Megaproject

The analysis provided in Chapter 4 has shown that Beaufort Sea production is very close to Hibernia production in per barrel cost. However, Hibernia has been chosen as the more immediate productive source notwithstanding the future potential of the Beaufort Sea region.

This decision is based largely upon the economic impact of the Hibernia project on the economy of the Atlantic provinces. The economic development aspects of the project provide policy-makers with a rationale for subsidization of the Hibernia project.

Similar arguments could be made for opportunities in the Beaufort Sea. However, the population of the northern territories is considerably less than that of Atlantic Canada and hence commands somewhat less policy attention. In addition, the obligation on the part of the Government of Canada to the reduction of regional economic disparities among the partners in Confederation does not apply equally to the northern territories.

Beaufort Sea opportunities should be studied with the goal of determining the optimal investment and social timing for this important Canadian resource.

7.7 Condensate Supplies: Exports and Petrochemicals

Condensate production in Canada has many potential uses. Two major uses are as a petrochemical feedstock and as diluent for exports of heavy products. It is important that Canada optimize its uses of limited hydrocarbon resources, particularly in view of the expectation that light oil products and various natural gas liquids will be in limited supply. A potential future conflict between use of condensates for petrochemical feedstock rather than heavy oil diluent will require public policy intervention to arrive at a solution reflecting the interests of all Canadians.

Assessments of the future markets for heavy oil and associated diluent in the United States should be conducted, including resource assessments in competing supply areas such as Venezuela. Long-term supply assessments of lighter petroleum crudes should be conducted in an effort to optimize long-term use of these valuable resources.

7.8 Free Trade Supply

This study has not analyzed or included current trade barriers or the effects of the Free Trade Agreement with the United States. However, if world oil prices remain low, Canada will require increasing volumes of light oil imports. The Free Trade Agreement proposes that Canada continue to export the proportion of oil it now exports to the United States and that, if we choose to cut back on production of this declining resource, we must cut back in equal proportions between Canadian consumption and exports to the United States.

This provision was established to accommodate world shortages in oil. However, Canada will experience a shortage in light crude oil under conditions of low crude oil prices and global light oil surplus supply conditions. In addition, Canadians have agreed to subsidize the development of nonconventional and frontier sources of light oil in Canada. This subsidy is permitted in the Free Trade Agreement. If the price of oil remains low and we are required to continue to export a constant proportion of light crude oil to the U.S., then actions taken to advance nonconventional and frontier light crude oil production would be tantamount to Canadian taxpayers subsidizing U.S. oil consumers.

This and other issues relating to future development of Canada's hydrocarbon resources will come under increasing scrutiny as we move through the 1990s. Certainly, the potential issue surrounding the possible subsidization of light crude oil exports begs analysis and policy review and resolution now, before it develops into a policy problem. The challenge to both industry and government is to pursue the most efficient and economic development and exploitation of Canada's crude oil resources.

Footnotes

¹Richard Brealey and Stewart Meyers, Principles of Corporate Finance (New York: McGraw-Hill, 1981).

APPENDIX A
SUPPLY MODELLING AND
INPUT ASSUMPTIONS



Appendix A

SUPPLY MODELLING AND INPUT ASSUMPTIONS

A.1 Canadian Oil Supply Analysis

The complexity of the different types, qualities and costs of crude oil in Canada has required the use of a computer modelling system to analyze the supply alternatives. That system as well as supporting systems used to fully analyze the Canadian crude oil alternatives are presented in this Appendix.

A.2 The Alberta Research Council Models

A model must be judged according to the purposes for which the model is to be used. When analyzing the supply/demand balances of crude oil in Canada, we looked for a model which could measure optimal allocation as well as various production technologies. Few models are equipped to optimize both inter-temporally and inter-regionally using Canadian oil supplies and demands.

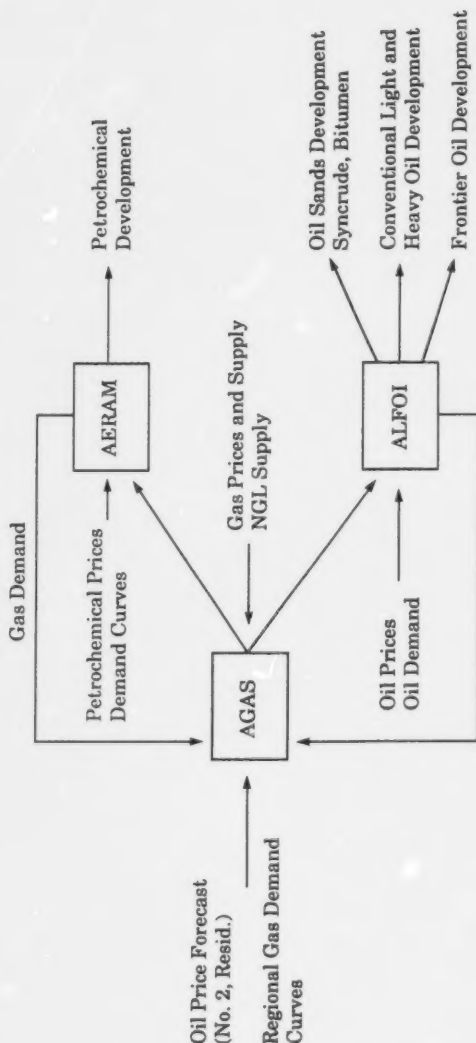
In the Alberta Research Council ALF01 we found an oil supply/demand model which optimizes inter-temporally and regionally, as well as incorporating various supply technologies and costs. ALF01 is a linear programming model which analyzes the supply and demand balances of liquid fuels in Canada. The model can be linked with similar models which analyze gas supplies and demands (AGAS) and the petrochemical industry configuration for Canada (AERAM). These three models are described as the "ARC Suite of Energy Models." A schematic diagram of these models is presented in Figure A.1.

Although CERI is primarily interested in the results of ALF01, both AGAS, which is a partial equilibrium natural gas trade model for North America, and AERAM, which is a detailed petrochemical model for Canada, provide necessary and interesting inputs to the analysis.

A.3 A Liquid Fuels Model: ALF01

ALF01 is the core model of the supply section of the CERI crude oil supply/demand balance study. This linear programming

Figure A.1
Schematic of Alberta Research Council Models



SOURCE: Alberta Research Council.

model is able to optimize oil uses in Canada and provide crude oil supply/demand balances for Canada given different market scenarios. ALF01 was employed to produce the supply/demand balances presented in this study, given the base case price assumptions discussed in Chapter 2, and the cost and technology assumptions and demand inputs from the CREED Model. The system also provides information on condensate balance and an approximation of likely economic rents available from the exploitation of Canadian crude oil resources.

A.4 Assessing the Model

Most models are only as good as the input assumptions which are provided to them. However, models can be ranked by their level of aggregation, calculation methodology, and flexibility, among other criteria. ALF01's characteristics are satisfactory in all of these areas.

A.4.1 Structure

ALF01 is disaggregated into the major supply regions of Western Canada, East Coast offshore, Beaufort Sea and Arctic Islands. Western Canada is further divided into light oils, heavy oils, bitumen and integrated synthetic crude oil projects.

The model is also disaggregated into three demand regions: Western Canada, Central Canada and Atlantic Canada. Demand is further divided into light oil and heavy oil demand. Demand estimates are exogenous inputs and must be provided using an exogenous demand model. CERI's CREED model proved to be an appropriate tool for this task.

A.4.2 Calculation Methodology

ALF01 uses a linear programming procedure to minimize the total costs of meeting the demand for liquid fuels in Canada over the forecast period. Alternative supply sources include imported crude and production from technologies currently available. Import prices are beyond the control of Canada and must therefore be input exogenously.

Corresponding to each domestic energy producing technology is a resource base, with a monotonically increasing supply cost curve. In a linear model, such as ALF01, the latter is approximated by a staircase-like set of discrete steps. Naturally, the model will try to produce from the lowest cost resource step first. However, a resource

step cannot be produced all at once. In order to convert a resource base to a reserve capable of being produced economically, capital investment is required (exploration and development expenditures in the case of conventional crudes and bitumen, plant and equipment expenditures in the case of mined oil sands), resulting in a production or deliverability capability over time. As a consequence of this limit on deliverability, production from several reserves steps may be required to satisfy demand at any given time.

The present value of all capital expenditures, discounted at some appropriate rate, is calculated for one specific point in time, which we have chosen to be the year in which production commences. The discounted volume of all subsequent production, discounted at the same rate, to the same point in time, is calculated. Dividing the present value by the discounted volume gives the levelized capital charge per unit of production. Adding the marginal operating costs (including fuel and material input) gives the total unit cost of production.

CERI's goal was to attempt to model the real world supplies based upon a range of likely costs and quantities, production constraints, drilling capacities and capital constraints. By introducing detail into the supply cost curve and constraints into the modelling system, we have been able to take advantage of the model's strengths.

A.4.3 Model Flexibility

The tremendous flexibility of ALF01 in analyzing various technologies and supply sources stems largely from the resources supplied by the ARC and their familiarity with the computer environment in which the model exists. The constraints on flexibility relate to the aggregate nature of the system and the calculation methodology. In its current form, model inputs are required for oil prices; for demand by type of oil and by region; for supply costs, quantities and other constraints; and for government and regulatory conditions. ALF01 interfaces with AGAS which itself requires a series of assumptions. However, for the purposes of this paper the input from AGAS is accepted as calculated.

The flexibility of ALF01 allows all relevant technologies to be appropriately modelled. We chose to analyze Canada on a fairly aggregate level; however, more regions and additional technologies could be easily introduced into the structure.

A.5 Regional Divisions: Supply Model

In order to analyze the existing and potential supply of crude oil in Canada, the supply basins were divided into four regions. These are:

1. The Western Sedimentary Basin
2. Beaufort Sea and Tuktoyaktuk Peninsula
3. East Coast Offshore
4. The Arctic Islands

Each of these regions exhibits different cost and transportation characteristics, as well as different production and reserves problems. Each region is analyzed separately by category of production expected from that area. The results of this analysis were then input into the ALF01 linear programming model.

A.6 Energy Technologies

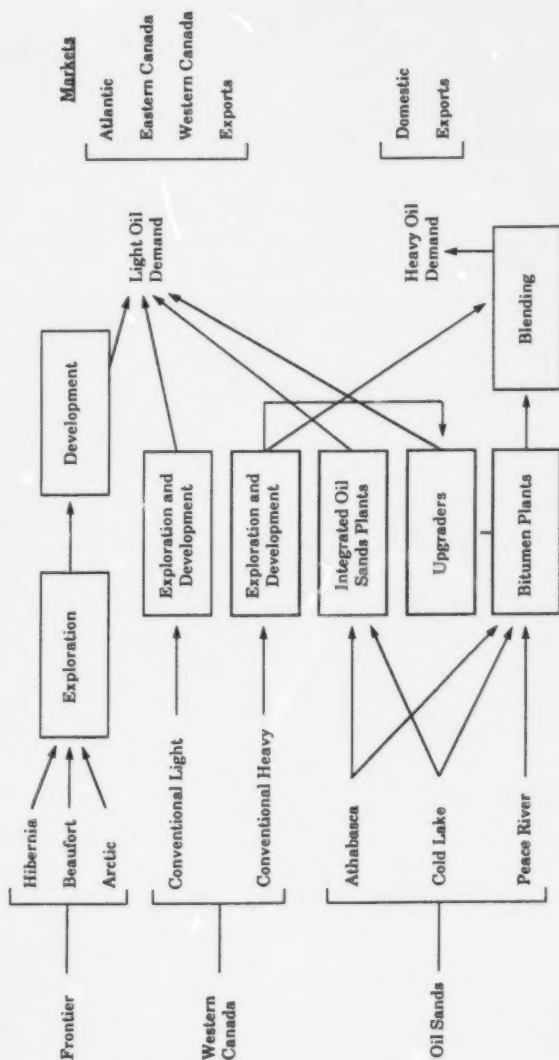
A.6.1 Model Supply Technologies

ALF01 has been designed so that any energy supply source can be added to the supply portfolio by specifying the respective costs, timing and quantity of oil available. The linear programming structure requires certain specific inputs in order to assimilate the technological aspects of any particular source of supply. A schematic diagram of this structure in ALF01 is presented in Figure A.2.

The sources of supply included in the most recent model are:

1. Western Canadian Light/Medium Crude Supply.
2. Western Canadian Heavy Crude Supply.
3. Western Canadian Bitumen Supply (In situ development).
4. Oil Sands Supplies - Integrated Mined Synthetic Crude.
5. Upgrader Supply with both heavy oil and bitumen feedstocks.
6. Beaufort Area Supply.
7. East Coast Offshore Supply.
8. Arctic Islands Supply.

Figure A.2
ALFO1



SOURCE: Alberta Research Council.

A.6.2 Modelling Regional Balances

As mentioned above, ALF01 contains three demand regions, accessing light crude oil supplies either by imports or by domestic, economically feasible supply sources. The Atlantic region can be supplied by Hibernia or by imports. Central Canada can be supplied with oil from the Western Sedimentary Basin or from Hibernia, otherwise the oil must come from imports. Western Canada's demand is generally met by Western Canadian supply.

Heavy oil supplies are either consumed internally in Western or Central Canada or exported. All Canadian demand for heavy oil is assumed to be met with Canadian supplies.

A.6.3 Condensate Balances

Condensate demand comes from diluent demand for heavy oil or bitumen transport, EOR demand for use in miscible floods, or crude oil demand in general.

Several sources of condensate supply are represented in the system. The basic source of condensate supply comes from the natural gas stream which has been modelled in the ARC gas model, AGAS. Additional supplies are available from other sources at higher prices. The ARC estimates that additional condensate is available over and above that currently extracted from the oil pool. Additional refinery naphtha is also available at premium prices. Once the price rises high enough, miscible flood begins to access lower cost alternatives thus freeing up additional supplies of condensate. The Dome NGL system could supply additional diluent at an appropriate price, while a back stop solution would be to recycle diluent from heavy oil exports to the PADD II area of the U.S.

Each of these additional supply sources requires an increasing premium price of condensate to be effective. For purposes of this study, each of these sources is limited to a specific supply per annum.¹

A.6.4 Oil Streams and Refinery Requirements

The qualities into which oil is divided in this model are conventional light oil, heavy oil, heavy oil blend, condensate, synthetic crude, and bitumen blend. Although the model does not address more detailed oil quality issues, the chemical subtleties between synthetic

crudes and conventional light oil or heavy oil blend and bitumen blend are addressed briefly below.

Clearly, there are different uses for and qualities of the coking products which come out of the current synthetic oil plant process. Coking products are suitable for generating certain refinery products but are inappropriate for others. There are concerns that these products will not be capable of supplying all types of refineries with feedstock without adding supplementary sources of conventional crude. Recent proposals for additional upgraders include new technologies, specifically hydrogen addition methods. Presumably these new upgrading technologies will expand the spectrum of products and refinery uses for synthetic crude, thereby precluding any constraints on synthetic oil production in providing a larger share of total Canadian crude oil supply.

The same type of problem is encountered in shipping Canadian heavy crude and bitumen to American markets. As the crude stream becomes heavier, the question arises as to whether American refineries will demand the same volumes of oil imports, and whether prices will remain relatively firm for such lower quality products. As with the increasing supply of synthetic crude, these issues are not specifically addressed by this modelling system. We have assumed that, with technological advances, these potential constraints will not become effective.

A.6.5 Royalties

For light/medium and heavy conventional crude oil, royalties are represented as a fraction of the difference between wellhead price and operating costs. Royalty rates are differentiated between production from already discovered reserves (30 percent for both light/medium and heavy oil production) and production from reserves additions (25 percent for both crude oil categories). For purposes of this analysis, royalty rates are assumed to be constant throughout the forecast period. It should be noted that the ARC framework can readily accommodate variable royalty rate structures.

For nonconventional and synthetic crude oil production, royalty rates are represented as a fraction of the wellhead price. Although actual royalty schedules for this category of crude oil usually feature a sliding rate schedule, increasing from 0 to 5 percent over some fixed production period, for simplicity we have assumed a constant royalty rate of 5 percent throughout the forecast period.

A.7 Other Supply Assumptions

As stated earlier, the model results are based upon input assumptions about costs and quantities available from each region and/or technology. Although three different price scenarios are run, the cost and quantity assumptions remain the same in each case. The model, therefore, can choose different projects or sources of supply depending upon the prices assumed. Cost assumptions in the model determine the timing of availability of these different sources of supply. Thus, the methodology implies that the major unknown factor is the future price of crude oil, rather than the costs of any particular technology.²

A.7.1 General Model Assumptions

There exist within this model various assumptions or "switches" which can affect the timing, level of development and/or the total cost of any particular project. The discount rate is an important example of such an assumption.

A constant discount rate of 12 percent in real terms has been used for our base case run. A 12 percent real rate of return was used because longer projects generally require an average of 16 percent to 18 percent return in nominal terms, depending upon the particular risks involved. If a project contains high, up-front capital expenditures and an income stream which begins well after the initial expenditures are complete, higher discount rates will lower the project's economic return while a lower discount rate will improve the economics of the project. Because not all projects contain similar requirements for capital, nor do they have the same income streams, changes in the discount rate will have different effects upon different projects.

Therefore, we have found it useful to run scenarios on several different projects, using different discount rates. This tests the responsiveness to changes in the required rate of return, which is another assessment of risk beyond that associated with oil prices.

There are other important assumptions which we have introduced to this linear programming model which will affect the timing of such projects. A limit was set on oil exports of 400 million barrels per year. This assumption is based upon the authors' opinion that even under much higher prices there will be an upper limit on the light oil that Canada will export, due to the limited supplies of light oils and recurrent security of supply concerns within Canada. Limits

were also assumed on heavy oil exports of 170 million barrels per year, a level associated with saturation of the American market.³

Timing limits have also been placed upon the construction of integrated mined oil sands plants and heavy oil upgraders. Oil sands plant construction has been limited in the model to a maximum of one 70,000 barrel per day plant every 3 years. Upgraders have been limited to a maximum of one 50,000 barrel per day plant every 2 years. These limitations are based upon limits to construction capacity in Alberta and Saskatchewan, which could not support more activity than this without major cost inflation which would, in turn, impact negatively on the plant costs input to the framework.

These model assumptions can be easily altered to meet changing circumstances. These constraints are not all necessarily effective in any particular case.

Footnotes

¹Condensate supply and disposition is provided in Appendix E for each of the simulations contained in this study.

²The royalty rates used in this analysis are representative rates. The royalty build-up properties for nonconventional and frontier developments have not been explicitly accounted for. Scenarios using alternative royalty regimes and the resulting impact on project returns can be accessed through the Alberta Research Council.

³H. F. Zey, "How Will the U.S. (Padd II) Respond to Increased Supply of Canadian Heavy Oil in the Mid 90's?", paper presented to the Conference Heavy Oil Who Needs It? How Will They Get It?, sponsored by the Canadian Heavy Oil Association (Calgary: Info-Tech, a division of Oil Week, December 8, 1987), Section 6.



APPENDIX B**ESTIMATION EQUATIONS,
CONVENTIONAL RESERVES ADDITIONS**



Appendix B

ESTIMATION EQUATIONS, CONVENTIONAL RESERVES ADDITIONS

This appendix contains the estimation equation procedure and results used to estimate reserves additions in the Western Sedimentary Basin.

$$Y = Q (1 - e^{ax+b}) \quad (1)$$

where:

Y = Cumulative Reserves Discovered
 Q = Ultimate Potential
 x = Cumulative Exploratory Effort
 a = Estimated Coefficient
 b = Constant in Estimated Equation

This equation was transformed in order to make it possible to perform a regression analysis into the following forms:

$$\ln (1 - Y/Q) = ax + b \quad (2)$$

In this form, $\ln(1 - Y/Q)$ is the dependent variable and x is the independent variable where a is the coefficient and b is the constant.

TABLE B.1
ESTIMATED COEFFICIENTS

Case	a	b
Low Case	-1.367746×10^{-5}	-.81645
Base Case	$-1.1729476 \times 10^{-5}$	-.767336
High Case	-9.61098×10^{-6}	-.70030

SOURCE: Canadian Energy Research Institute.

The three equations for forecasting reserve additions are then:

Low Case

$$Y = 3376 (1 - e^{[-0.00001367746 \cdot \text{Cumulative Drilling}] + -.81645})$$

Base Case

$$Y = 3536 (1 - e^{[-0.000011729476 \cdot \text{Cumulative Drilling}] + -.767336})$$

High Case

$$Y = 3786 (1 - e^{[-0.00000961098 \cdot \text{Cumulative Drilling}] + -.70030})$$

APPENDIX C
COST INFORMATION ON
CRUDE OIL SUPPLY



Appendix C

COST INFORMATION ON CRUDE OIL SUPPLY

As stated in the body of the paper, the cost inputs to the model remained the same in each price case which was run. In this appendix the cost tables from the ALF01 model are provided with explanations as to their meaning.

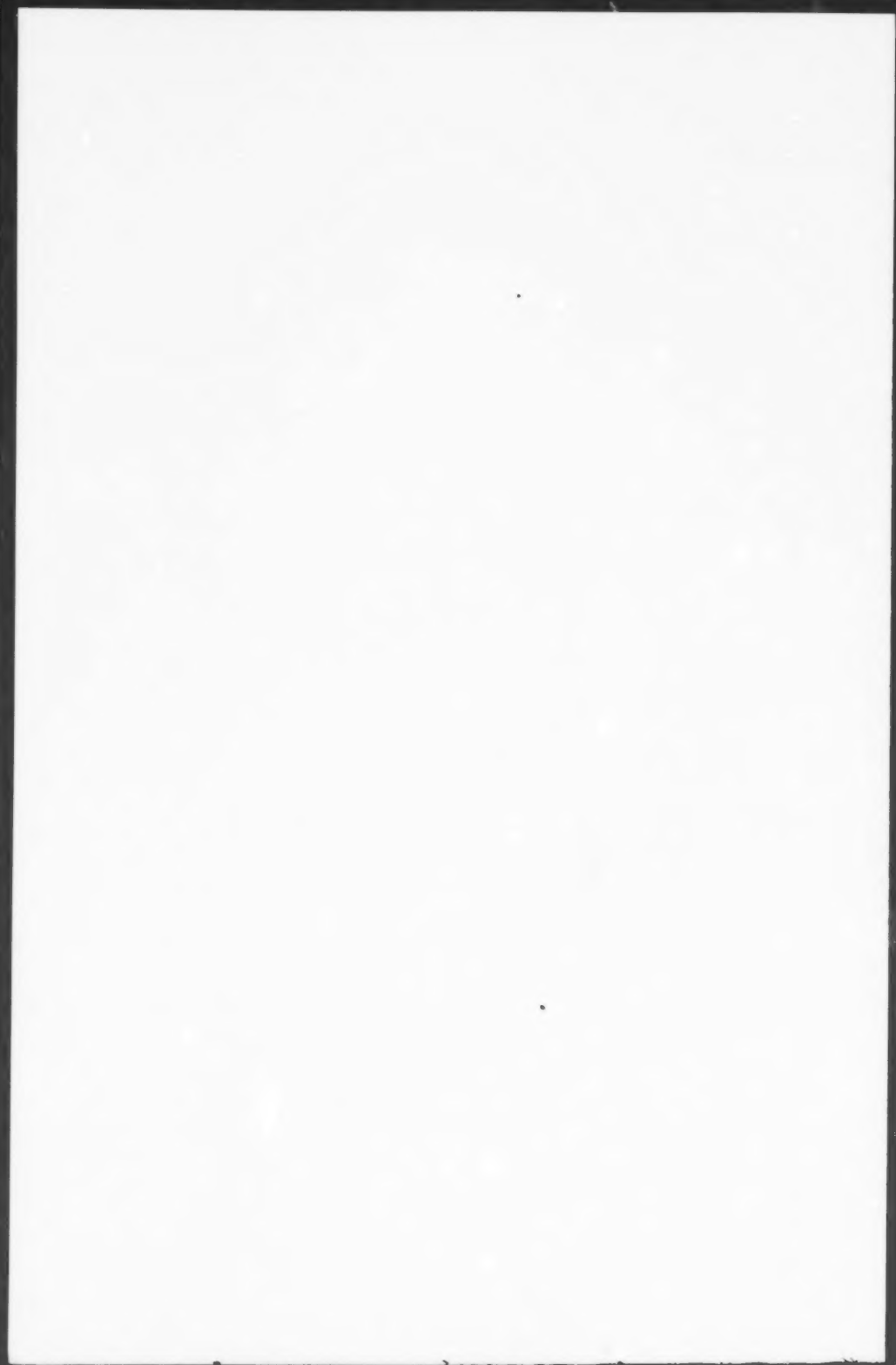


TABLE C.1
ALF01 NOMENCLATURE

Acronym	Definition
WC1	Western Sedimentary Basin Light Crude, discovered and producing.
WC2	Western Sedimentary Basin Light Crude, yet to be discovered.
WH1	Western Sedimentary Basin Heavy Crude, discovered and producing.
WH2	Western Sedimentary Basin Heavy Crude, undiscovered or discovered but uneconomic at current prices.
FX1, FX2	Discovered reserves in the Hibernia region.
FC1, FC2, FC3, FC4	Undiscovered East Coast offshore reserves, defined for various cost levels.
BX1, BX2	Discovered reserves in the Beaufort Sea region.
BC1, BC2, BC3, BC4	Undiscovered Beaufort Sea region reserves at various cost levels.
MS1	Syncrude/Suncor integrated mined oil sands plants.
OSL	Proposed OSLO oil sands plant.
HC1	Eso Cold Lake in-situ bitumen project.
SP1	Peace River in-situ bitumen project.
HUP	Heavy oil upgrader project.

SOURCE: Alberta Research Council.

TABLE C.2
TRANSPORTATION AND BLENDING COSTS

	Transport (\$/barrel)	Capacity (MMb/yr.)
Beaufort to Alberta, light crude	8.00	--
Alberta to Toronto, light crude	1.50	300.0
Maritimes to Toronto, light crude	4.50	--
Alberta to Chicago, light crude	1.52	110.0
Alberta to Chicago, heavy oil blend	1.90	--
Blending heavy oil and diluent	1.00	--
Blending bitumen and diluent	1.00	--

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

TABLE C.3
ROYALTY RATES BY TYPE OF CRUDE
1985 - 2008

Year	WC1 ^a	WC2 ^a	WH1 ^a	WH2 ^a	MS1 ^b	OSL ^b	CL1 ^b	BIT ^b
1988	.30		.30		.05	.05	.05	.05
1989	.30		.30		.05	.05	.05	.05
1990	.30		.30		.05	.05	.05	.05
1991	.30		.30		.05	.05	.05	.05
1992	.30	.24	.30	.24	.05	.05	.05	.05
1993	.30	.24	.30	.24	.05	.05	.05	.05
1994	.30	.24	.30	.24	.05	.05	.05	.05
1995	.30	.24	.30	.24	.05	.05	.05	.05
1996	.30	.24	.30	.24	.05	.05	.05	.05
1997	.30	.24	.30	.24	.05	.05	.05	.05
1998	.30	.24	.30	.24	.05	.05	.05	.05
1999	.30	.24	.30	.24	.05	.05	.05	.05
2000	.30	.24	.30	.24	.05	.05	.65	.05
2001	.30	.24	.30	.24	.05	.05	.05	.05
2002	.30	.24	.30	.24	.05	.05	.05	.05
2003	.30	.24	.30	.24	.05	.05	.05	.05
2004	.30	.24	.30	.24	.05	.05	.05	.05
2005	.30	.24	.30	.24	.05	.05	.05	.05
2006	.30	.24	.30	.24	.05	.05	.05	.05
2007	.30	.24	.30	.24	.05	.05	.05	.05
2008	.30	.24	.30	.24	.05	.05	.05	.05

SOURCES: Alberta Research Council and Canadian Energy Research Institute.

^aRoyalties are expressed as a fraction of the difference between wellhead price and operating costs.

^bRoyalties are expressed as a fraction of the wellhead price.

TABLE C.4
COSTS OF ENERGY TECHNOLOGIES

	Categories ^a					
	MCG (\$/bbl)	DSR (%)	AED (\$/bbl)	OPR (\$/bbl)	TOT (\$/bbl)	RSV (MMb)
Conventional Light Crude						
WC1		12		3.50	3.50	4370
WC2	6.20	12	14.48	4.50	18.98	5000
Beaufort Light Crude Discovered						
BX1	4.14	12	17.73	7.00	24.73	600
BX2	4.35	12	18.62	9.00	27.62	250
Beaufort Light Crude Undiscovered						
BLC	2.00	12	9.08			6400
BC1	4.48	12	19.17	14.50	33.67	2240
BC2	4.70	12	20.13	16.50	36.63	800
Hibernia Light Crude Discovered						
FX1	4.99	12	23.02	14.00	37.02	530
FX2	5.12	12	23.48	16.00	39.48	300
Hibernia Light Crude Undiscovered						
FLC	3.00	12	13.61			3000
FC1	5.27	12	24.17	24.00	48.17	
FC2	5.54	12	25.39	26.00	51.39	750
Oil Sands and Related Technologies ^b						
MS1	5.71	12	22.46	12.10	34.56	5900
OSL	4.70	12	19.84	12.82	32.66	3000
HC1	2.16	12	6.05	5.06	11.11	1300
SP1	3.15	12	9.34	4.89	14.23	1025
HUP	2.60	12	8.58	2.88	11.46	
Heavy Crude						
WH1		12		5.50	5.50	800
WH2	6.00	12	14.02	6.00	20.02	2000

SOURCES: Canadian Energy Research Institute and Alberta Research Council.

^aNomenclature used in this table is as follows:

MCG - in-ground pre-production costs (\$/bbl)
 DSR - discount rate (%)
 AED - amortized pre-production costs (\$/bbl);
 OPR - operating cost (\$/bbl);
 TOT - total costs (\$/bbl);
 RSV - reserves in each category (MMB)

^bNatural gas costs are excluded from these figures.

TABLE C.5
PROJECTED TOTAL PER BARREL COSTS,
SELECTED TECHNOLOGIES^a
(1988-2008)

Year	Oil Sands Plant (\$/bbl)	OSLO Project (\$/bbl)	Cold Lake Project (\$/bbl)	Peace River Project (\$/bbl)	Heavy Oil Upgrader (\$/bbl)
1988	35.35	34.66	13.25	16.87	12.77
1989	35.39	34.76	13.36	17.01	12.84
1990	35.49	35.01	13.63	17.34	13.00
1991	35.58	35.24	13.87	17.64	13.15
1992	35.62	35.35	13.99	17.79	13.23
1993	35.67	35.48	14.13	17.96	13.31
1994	35.72	35.61	14.27	18.14	13.40
1995	35.78	35.75	14.42	18.32	13.49
1996	35.83	35.89	14.57	18.50	13.58
1997	35.89	36.03	14.73	18.70	13.68
1998	35.95	36.19	14.90	18.91	13.78
1999	36.02	36.35	15.07	19.12	13.89
2000	36.08	36.52	15.25	19.35	14.00
2001	36.20	36.82	15.57	19.74	14.20
2002	36.31	37.11	15.87	20.12	14.38
2003	36.43	37.40	16.19	20.51	14.58
2004	36.51	37.60	16.40	20.77	14.71
2005	36.60	37.82	16.64	21.07	14.86
2006	36.70	38.08	16.91	21.40	15.02
2007	36.79	38.31	17.17	21.72	15.18
2008	36.88	38.53	17.40	22.01	15.32

SOURCES: Canadian Energy Research Institute, and Alberta Research Council.

^aCosts include natural gas process costs, but exclude feedstock costs. Costs expressed in constant 1986 Canadian dollars per barrel.



APPENDIX D**PRODUCTION SCENARIOS FROM
DIFFERENT SUPPLY SECTORS**

- D.1 Low Price Case - Prudent Industrial Behaviour***
- D.2 Base Case - Prudent Industrial Behaviour***
- D.3 High Price Case - Prudent Industrial Behaviour***
- D.4 Base Case - Perfect Foresight***
- D.5 Base Case - All Megaprojects***
- D.6 High Price Case - All Megaprojects***



D.1 LOW PRICE CASE
PRUDENT INDUSTRIAL BEHAVIOUR



TABLE D.1a
PRODUCTION OF CRUDE OIL AND EQUIVALENT
ALL SOURCES
(MMb/yr.)

Year	Light/Medium Conventional	Heavy Oil ^a	Synthetic Crude	Bitumena	Frontier	Total
1988	352.2	77.8	77.8	51.7	0.0	559.5
1989	322.8	73.2	91.6	39.5	0.0	527.1
1990	295.0	54.0	94.6	42.3	0.0	485.9
1991	271.0	50.9	94.6	42.3	0.0	458.8
1992	249.4	51.4	96.6	42.3	0.0	439.7
1993	232.9	52.1	96.6	42.3	0.0	423.9
1994	213.6	54.0	96.6	42.3	0.0	406.5
1995	198.5	52.5	96.6	42.3	0.0	389.9
1996	187.6	50.0	96.6	42.3	0.0	376.5
1997	176.8	47.3	96.6	42.3	0.0	363.0
1998	168.0	45.5	96.6	56.1	0.0	366.2
1999	160.2	43.7	96.6	62.5	0.0	363.0
2000	152.9	42.7	93.6	62.5	0.0	351.7
2001	145.5	41.5	89.6	62.5	0.0	339.1
2002	138.9	41.1	80.6	62.5	0.0	323.1
2003	133.0	39.6	71.6	62.5	0.0	306.7
2004	127.3	39.0	71.6	62.5	32.0	332.4
2005	122.4	38.3	77.8	62.5	45.1	346.1
2006	118.6	37.5	71.6	62.5	46.3	336.5
2007	114.5	36.7	77.3	68.4	59.6	356.5
2008	110.3	36.8	94.3	71.0	65.0	377.4

SOURCE: Canadian Energy Research Institute.

^aTotals include volumes utilized as feedstock to the Coop and Lloydminster Upgraders.

TABLE D.1b
DETAILED PRODUCTION SUMMARY
ALL ECONOMIC SOURCES
(MMb/yr.)

Year	Light/Medium Conventional Oil		Heavy Oil		Synthetic Crude Oil		
	Discovered	Undiscovered	Discovered	Undiscovered	Existing	Expansion	Coop Lloydminster Upgrader
1988	290.0	62.2	69.0	8.8	70.0		7.8
1989	254.0	68.8	61.0	12.2	76.0		15.6
1990	223.0	72.0	54.0	0.0	79.0		15.6
1991	198.0	73.0	47.0	3.9	79.0		15.6
1992	176.0	73.4	42.0	9.4	81.0		15.6
1993	159.0	73.9	37.0	15.1	81.0		15.6
1994	139.0	74.6	32.0	22.0	81.0		15.6
1995	123.0	75.5	29.0	23.5	81.0		15.6
1996	111.0	76.6	25.0	25.0	81.0		15.6
1997	99.0	77.8	21.0	26.3	81.0		15.6
1998	89.0	79.0	18.0	27.5	81.0		15.6
1999	80.0	80.2	15.0	28.7	81.0		15.6
2000	72.0	80.9	13.0	29.7	78.0		15.6
2001	64.0	81.5	11.0	30.5	74.0		15.6
2002	57.0	81.9	10.0	31.1	65.0		15.6
2003	51.0	82.0	8.0	31.6	56.0		15.6
2004	45.0	82.2	7.0	32.0	56.0		15.6
2005	40.0	82.4	6.0	32.3	56.0		15.6
2006	36.0	82.6	5.0	32.5	56.0		15.6
2007	32.0	82.4	4.0	32.7	56.0	5.7	15.6
2008	28.0	82.3	4.0	32.8	56.0	22.7	15.6

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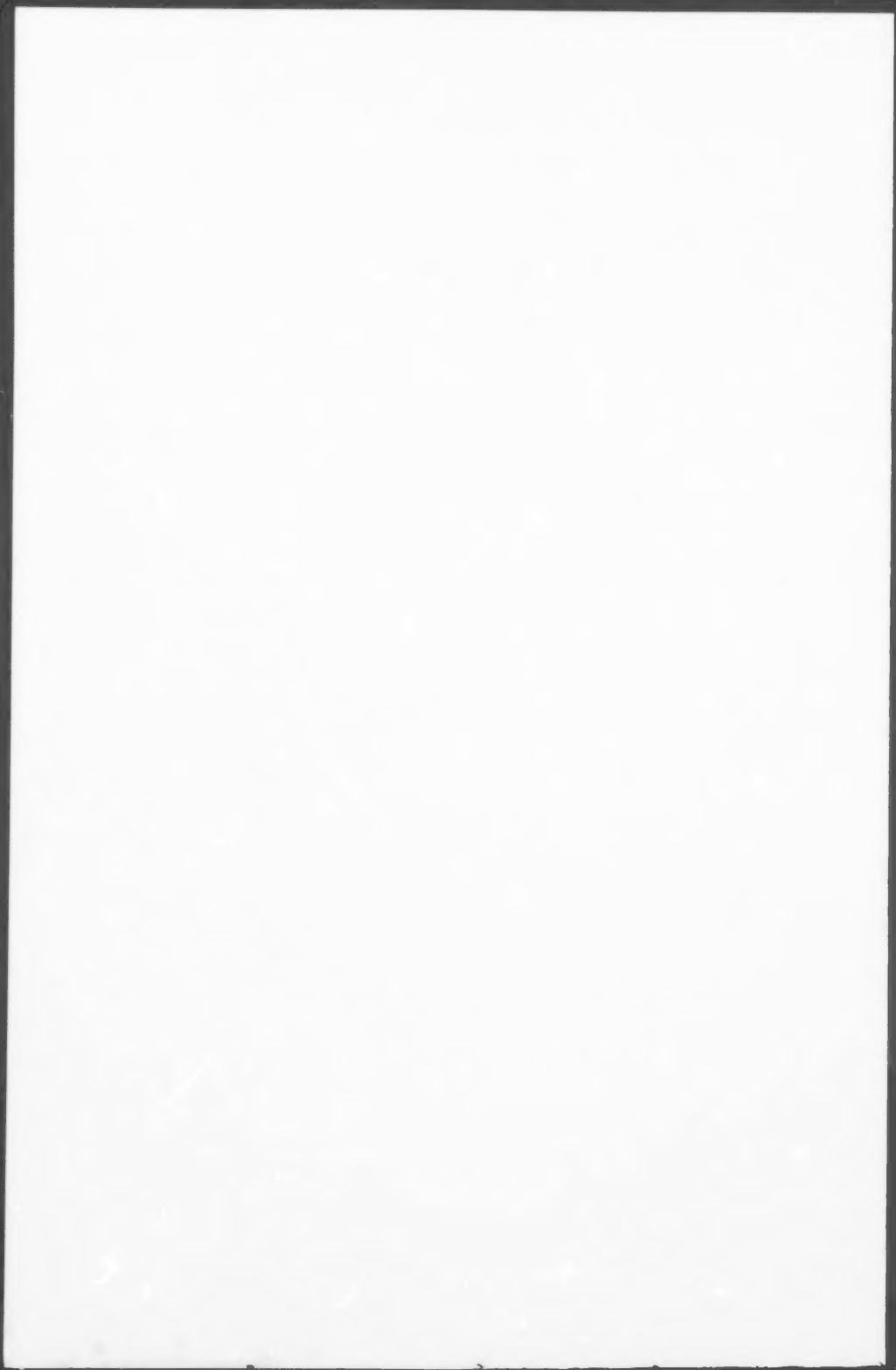
TABLE D.1b Continued

ALL ECONOMIC SOURCES
(MMb/yr.)

Year	Existing	Bitumen		Beaufort Discovered
		Cold Lake	Peace River	
1988	32.4	13.8	5.5	
1989	39.5			
1990	42.3			
1991	42.3			
1992	42.3			
1993	42.3			
1994	42.3			
1995	42.3			
1996	42.3			
1997	42.3			
1998	42.3	13.8		
1999	42.3	13.8	6.4	
2000	42.3	13.8	6.4	
2001	42.3	13.8	6.4	
2002	42.3	13.8	6.4	
2003	42.3	13.8	6.4	32.0
2004	42.3	13.8	6.4	45.1
2005	42.3	13.8	6.4	46.3
2006	42.3	13.8	6.4	59.6
2007	42.3	21.8	4.3	
2008	42.3	26.5	2.2	65.0

SOURCE: Canadian Energy Research Institute.

11



D.2 BASE CASE
PRUDENT INDUSTRIAL BEHAVIOUR

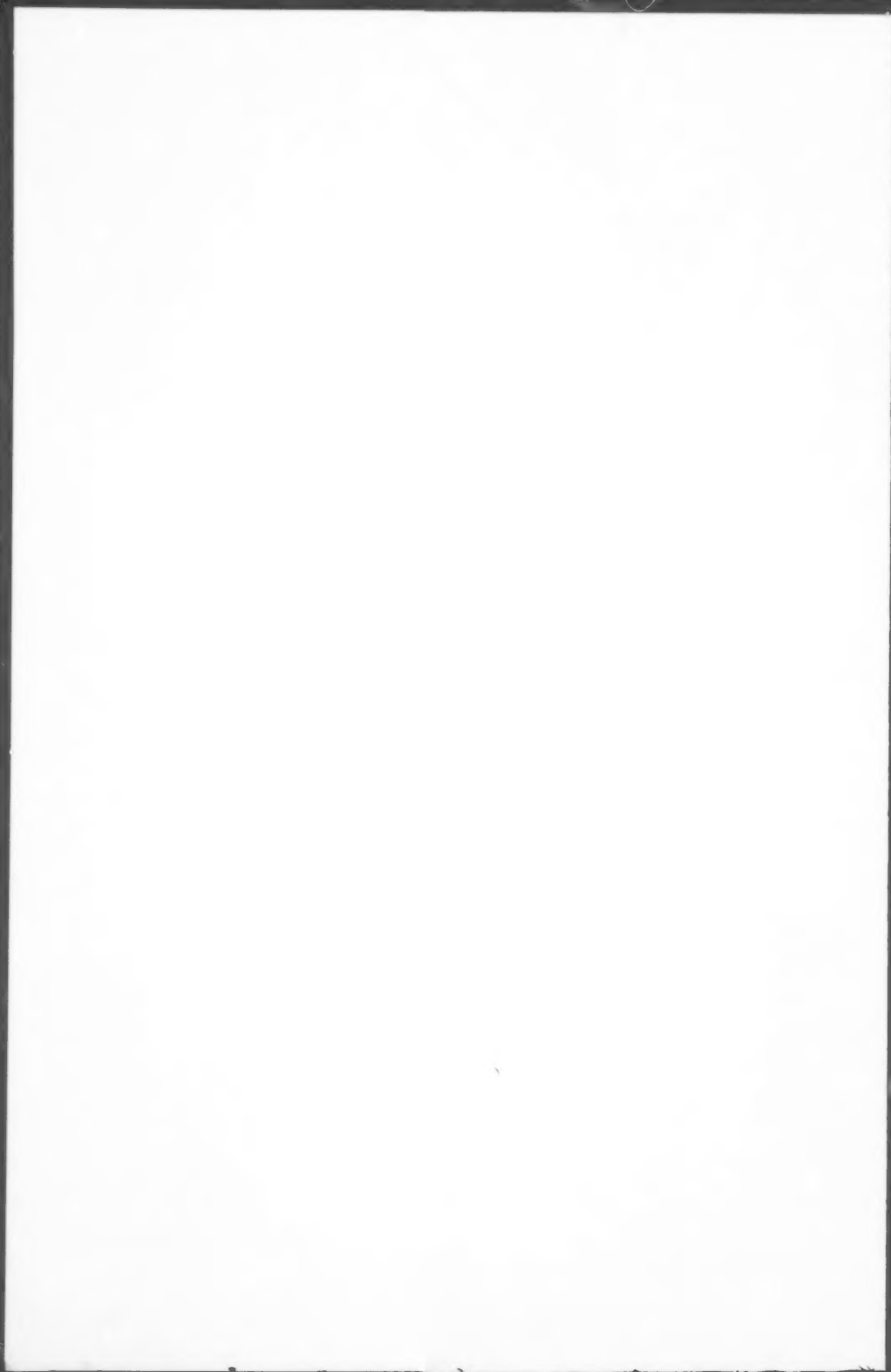


TABLE D.2a
PRODUCTION OF CRUDE OIL AND EQUIVALENT
ALL SOURCES
(MMb/yr.)

Year	Light/Medium Conventional	Heavy Oil ^a	Synthetic Crude	Bitumena	Frontier	Total
1988	353.4	78.3	77.8	51.7	0.0	561.2
1989	327.3	75.2	91.6	46.7	0.0	540.8
1990	304.4	73.0	94.6	53.8	0.0	525.8
1991	286.0	70.4	94.6	61.4	0.0	512.4
1992	269.9	69.5	96.6	62.5	0.0	498.5
1993	258.2	68.2	96.6	62.6	0.0	485.6
1994	242.8	66.4	96.6	62.5	0.0	468.3
1995	230.5	66.3	96.6	62.5	0.0	455.9
1996	221.7	64.7	96.6	72.2	0.0	455.2
1997	212.6	62.8	96.6	73.6	0.0	445.6
1998	205.0	61.6	98.8	73.7	0.0	439.1
1999	197.7	60.1	99.4	73.7	0.0	430.9
2000	190.8	59.2	97.7	73.6	0.0	421.3
2001	183.3	58.0	93.7	75.1	0.0	410.1
2002	176.6	57.7	87.8	77.8	0.0	399.9
2003	170.5	56.1	94.8	91.6	0.0	413.0
2004	164.4	55.4	110.8	104.9	45.4	480.9
2005	159.4	54.6	116.9	110.4	63.8	505.1
2006	155.2	53.7	122.5	111.0	79.1	521.5
2007	150.8	52.8	139.6	108.9	155.0	607.1
2008	146.4	52.8	161.5	101.7	189.8	652.2

SOURCE: Canadian Energy Research Institute.

^aTotals include volumes utilized as feedstock to the Coop and Lloydminster Upgraders.

TABLE D.2b
DETAILED PRODUCTION PROFILE SUMMARY
ALL ECONOMIC SOURCES
(MMb/yr.)

Year	Light/Medium Conventional Oil		Heavy Oil		Synthetic Crude Oil		
	Discovered	Undiscovered	Discovered	Undiscovered	Existing	Expansion	Coop. Lloydminster Upgrader Upgrader
1988	290.0	63.4	69.0	9.3	70.0		7.8
1989	254.0	73.3	61.0	14.2	76.0		15.6
1990	223.0	81.4	54.0	19.0	79.0		15.6
1991	198.0	88.0	47.0	23.4	79.0		15.6
1992	176.0	93.9	42.0	27.5	81.0		15.6
1993	159.0	99.2	37.0	31.2	81.0		15.6
1994	139.0	103.8	32.0	34.4	81.0		15.6
1995	123.0	107.5	29.0	37.3	81.0		15.6
1996	111.0	110.7	25.0	39.7	81.0		15.6
1997	99.0	113.6	21.0	41.8	81.0		15.6
1998	89.0	116.0	18.0	43.6	81.0		15.6
1999	80.0	117.7	15.0	45.1	81.0		15.6
2000	72.0	118.8	13.0	46.2	78.0		15.6
2001	64.0	119.3	11.0	47.0	74.0		15.6
2002	57.0	119.6	10.0	47.7	65.0		15.6
2003	51.0	119.5	8.0	48.1	56.0		15.6
2004	45.0	119.4	7.0	48.4	56.0		15.6
2005	40.0	119.3	6.0	48.6	56.0		15.6
2006	36.0	119.2	5.0	48.7	56.0	5.7	15.6
2007	32.0	118.7	4.0	48.8	56.0	22.7	15.6
2008	28.0	118.3	4.0	48.8	56.0	44.6	15.6

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TABLE D.2b Continued

ALL ECONOMIC SOURCES
(MMb/yT.)

Year	Existing	Bitumen		Peace River	Beaufort		Hibernia	
		Cold Lake			Discovered	Undiscovered	Discovered	
1988	32.4	13.8		5.5				
1989	33.5	7.2						
1990	42.3	11.5						
1991	42.3	13.8		5.3				
1992	42.3	13.8		6.4				
1993	42.3	13.8		6.4				
1994	42.3	13.8		6.4				
1995	42.3	13.8		6.4				
1996	42.3	23.4		6.4				
1997	42.3	24.9		6.4				
1998	42.3	24.9		6.4				
1999	42.3	24.9		6.4				
2000	42.3	24.9		6.4				
2001	42.3	26.3		6.4				
2002	42.3	29.0		6.4				
2003	42.3	42.9		6.4				
2004	42.3	56.2		6.4				
2005	42.3	61.7		6.4	45.4			
2006	42.3	62.3		6.4	63.8		13.6	
2007	42.3	62.3		4.3	65.5	40.2	49.3	
2008	42.3	48.5		10.9	65.5	56.5	67.8	

SOURCE: Canadian Energy Research Institute.



D.3 HIGH PRICE CASE
PRUDENT INDUSTRIAL BEHAVIOUR



TABLE D.3a
PRODUCTION OF CRUDE OIL AND EQUIVALENT
ALL SOURCES
(MMb/yr.)

Year	Light/Medium Conventional	Heavy Oils ^a	Synthetic Crude	Bitumena	Frontier	Total
1988	355.5	78.9	77.8	51.7	0.0	563.9
1989	333.8	77.0	91.6	44.1	0.0	546.5
1990	315.6	76.1	94.6	49.3	0.0	535.6
1991	302.4	75.0	94.6	54.7	0.0	526.7
1992	291.4	75.5	96.6	54.4	0.0	517.9
1993	284.4	75.6	96.6	54.9	0.0	511.5
1994	273.4	75.1	101.7	62.5	0.0	512.7
1995	265.3	76.2	102.5	62.5	0.0	506.5
1996	260.2	75.7	118.5	83.9	0.0	538.3
1997	254.5	74.8	130.9	101.4	0.0	561.6
1998	249.8	74.6	146.9	107.8	0.0	579.1
1999	245.3	73.9	154.1	110.7	0.0	584.0
2000	240.6	73.8	155.6	111.0	0.0	581.0
2001	235.1	73.2	151.6	111.4	0.0	571.3
2002	230.0	73.4	144.4	112.7	0.0	560.5
2003	225.4	72.3	144.8	121.0	0.0	563.5
2004	220.6	72.1	160.8	134.0	45.4	632.9
2005	216.8	71.7	164.9	137.6	63.8	654.8
2006	213.7	71.2	170.6	137.6	168.7	761.8
2007	210.2	70.7	187.6	138.3	240.9	847.7
2008	206.7	71.0	209.5	134.7	262.7	884.6

SOURCE: Canadian Energy Research Institute.

^aTotals include volumes utilized as feedstock to the Coop and Lloydminster Upgraders.

TABLE D.3b
DETAILED PRODUCTION PROFILE SUMMARY
ALL ECONOMIC SOURCES
(MMb/yr.)

Year	Light/Medium Conventional Oil		Heavy Oil		Synthetic Crude Oil		
	Discovered	Undiscovered	Discovered	Undiscovered	Existing	Expansion	Coop Lloydminster Upgrader
1988	290.0	65.5	69.0	9.9	70.0		7.8
1989	254.0	79.8	61.0	16.0	76.0		15.6
1990	223.0	92.6	54.0	22.1	79.0		15.6
1991	198.0	104.4	47.0	28.0	79.0		15.6
1992	176.0	115.4	42.0	33.5	81.0		15.6
1993	159.0	125.4	37.0	38.6	81.0		15.6
1994	139.0	134.4	32.0	43.1	81.0		15.6
1995	123.0	142.3	29.0	47.2	81.0		15.6
1996	111.0	149.2	25.0	50.7	81.0		15.6
1997	99.0	155.5	21.0	53.8	81.0		15.6
1998	89.0	160.8	18.0	56.6	81.0		15.6
1999	80.0	165.3	15.0	58.9	81.0		15.6
2000	72.0	168.6	13.0	60.8	78.0		15.6
2001	64.0	171.1	11.0	62.2	74.0		15.6
2002	57.0	173.0	10.0	63.4	65.0		15.6
2003	51.0	174.3	8.0	64.3	56.0		15.6
2004	45.0	175.6	7.0	65.1	56.0		15.6
2005	40.0	176.7	6.0	66.7	56.0		15.6
2006	36.0	177.7	5.0	66.2	56.0	5.7	15.6
2007	32.0	178.2	4.0	66.7	56.0	22.7	15.6
2008	28.0	178.7	4.0	67.0	56.0	44.6	15.6

Continued on Next Page

TABLE D.3b Continued

ALL ECONOMIC SOURCES
(MMb/yr.)

Year	Bitumen		Peace River	Beaufort		Hibernia
	Existing	Cold Lake		Discovered	Undiscovered	
1988	32.4	13.8	5.5			
1989	39.5	4.6				
1990	42.3	7.0				
1991	42.3	12.4				
1992	42.3	12.1	6.4			
1993	42.3	12.6	6.4			
1994	42.3	13.8	6.4			
1995	42.3	13.8	6.4			
1996	42.3	35.2	6.4			
1997	42.3	52.7	6.4			
1998	42.3	59.0	6.4			
1999	42.3	61.9	6.4			
2000	42.3	62.3	6.4			
2001	42.3	62.3	6.8			
2002	42.3	62.3	8.1			
2003	42.3	62.3	16.5			
2004	42.3	62.3	29.5	45.4		
2005	42.3	62.3	33.0	63.8	89.6	13.6
2006	42.3	62.3	33.0	65.5	126.1	49.3
2007	42.3	62.3	33.7	65.5	129.4	67.8
2008	42.3	48.5	43.9	65.5		

SOURCE: Canadian Energy Research Institute.



**D.4 BASE CASE
PERFECT FORESIGHT**



TABLE D.4a
PRODUCTION OF CRUDE OIL AND EQUIVALENT
ALL SOURCES
(MMb/yr.)

Year	Light/Medium Conventional	Heavy Oils ^a	Synthetic Crude	Bitumens ^a	Frontier	Total
1988	353.4	78.3	77.8	51.7	0.0	561.2
1989	327.3	75.2	91.6	46.7	0.0	540.8
1990	304.4	73.0	94.6	53.8	0.0	525.8
1991	286.0	70.4	94.6	61.4	0.0	512.4
1992	269.9	69.5	96.6	62.5	0.0	498.5
1993	258.2	68.2	96.6	62.5	0.0	485.5
1994	242.8	66.4	96.6	62.5	0.0	468.3
1995	230.5	66.3	96.6	62.5	0.0	455.9
1996	221.7	64.7	96.6	72.2	0.0	455.2
1997	212.6	62.8	102.3	75.4	0.0	453.1
1998	205.0	61.6	129.7	84.1	0.0	480.4
1999	197.8	60.1	155.8	85.4	13.6	512.7
2000	190.8	59.2	193.1	95.5	81.3	519.9
2001	183.4	58.0	231.1	109.1	112.9	694.5
2002	176.6	57.7	251.7	111.0	127.4	724.4
2003	170.5	56.1	271.1	111.0	132.8	741.5
2004	164.4	55.4	305.4	111.0	132.8	769.0
2005	159.4	54.6	342.2	111.0	132.8	800.0
2006	155.3	53.7	370.6	111.0	132.8	823.4
2007	150.7	52.8	398.1	109.8	169.9	881.3
2008	146.3	52.8	419.2	104.4	175.1	897.8

SOURCE: Canadian Energy Research Institute.

^aTotals include volumes utilized as feedstock to the Coop and Lloydminster Upgraders.

TABLE D.4b
DETAILED PRODUCTION PROFILE SUMMARY
ALL ECONOMIC SOURCES
(MMb/yr.)

Year	Light/Medium Conventional Oil		Heavy Oil		Synthetic Crude Oil			
	Discovered	Undiscovered	Discovered	Undiscovered	Existing	Expansion	OSLO Upgrader	Coop Lloydminster Upgrader
1988	290.0	63.4	69.0	9.3	70.0			7.8
1989	254.0	73.3	61.0	14.2	76.0			15.6
1990	223.0	81.4	54.0	19.0	79.0			15.6
1991	198.0	88.0	47.0	23.4	79.0			15.6
1992	176.0	93.9	42.0	27.5	81.0			15.6
1993	159.0	99.2	37.0	31.2	81.0			15.6
1994	139.0	103.8	32.0	34.4	81.0			15.6
1995	123.0	107.5	29.0	37.3	81.0			15.6
1996	111.0	110.7	25.0	39.7	81.0			15.6
1997	99.0	113.6	21.0	41.8	81.0		5.7	15.6
1998	89.0	116.0	18.0	43.6	81.0		22.7	15.6
1999	80.0	117.7	15.0	45.1	81.0		44.6	15.6
2000	72.0	118.8	13.0	46.2	78.0	1.9	67.0	15.6
2001	64.0	119.3	11.0	47.0	74.0	11.5	83.5	15.6
2002	57.0	119.6	10.0	47.7	65.0	30.2	92.3	15.6
2003	51.0	119.5	8.0	48.1	56.0	52.9	98.0	15.6
2004	45.0	119.4	7.0	48.4	56.0	77.8	101.4	15.6
2005	40.0	119.3	6.0	48.6	56.0	104.4	103.3	15.6
2006	36.0	119.2	5.0	48.7	56.0	132.2	103.8	15.6
2007	32.0	118.7	4.0	48.8	56.0	159.7	103.8	15.6
2008	28.0	118.3	4.0	48.8	56.0	180.8	103.8	15.6

Continued on Next Page

TABLE D.4b Continued

ALL ECONOMIC SOURCES
(MMb/yr.)

Year	Bitumen		Peace River	Beaufort		Hibernia
	Existing	Cold Lake		Discovered	Undiscovered	
1988	32.4	13.8	5.5			
1989	39.5	7.2				
1990	42.3	11.5				
1991	42.3	13.8	5.3			
1992	42.3	13.8	6.4			
1993	42.3	13.8	6.4			
1994	42.3	13.8	6.4			
1995	42.3	13.8	6.4			
1996	42.3	23.4	6.4			
1997	42.3	26.7	6.4			
1998	42.3	35.3	6.4			
1999	42.3	36.6	6.4			
2000	42.3	46.7	6.4			
2001	42.3	60.4	6.4	32.0		13.6
2002	42.3	62.3	6.4	45.1		49.3
2003	42.3	62.3	6.4	59.6		67.8
2004	42.3	62.3	6.4	65.0		67.8
2005	42.3	62.3	6.4	65.5		67.8
2006	42.3	62.3	6.4	65.5		67.8
2007	42.3	62.3	5.3	61.9	40.2	67.8
2008	42.3	48.5	13.6	60.8	46.5	67.8

SOURCE: Canadian Energy Research Institute.



**D.5 BASE CASE
ALL MEGAPROJECTS**



TABLE D.5a
PRODUCTION OF CRUDE OIL AND EQUIVALENT
ALL SOURCES
(MMb/yr.)

Year	Light/Medium Conventional	Heavy Oils ^a	Synthetic Crude	Bitumens ^a	Frontier	Total
1988	353.4	78.3	77.8	51.7	0.0	561.2
1989	327.3	75.2	91.6	46.7	0.0	540.8
1990	304.4	73.0	94.6	53.8	0.0	525.8
1991	286.0	70.4	94.6	61.4	0.0	512.4
1992	269.9	69.5	96.6	62.5	0.0	498.5
1993	258.2	68.2	113.4	62.5	0.0	502.3
1994	242.8	66.4	113.4	62.5	0.0	485.1
1995	230.5	66.3	116.2	62.5	12.6	488.1
1996	221.7	64.7	124.6	85.9	45.7	542.6
1997	212.6	62.8	132.6	89.5	62.8	560.3
1998	204.9	61.6	136.2	89.5	62.8	555.0
1999	197.7	60.1	141.2	89.5	62.8	551.3
2000	190.7	59.2	155.7	99.6	62.8	568.0
2001	183.3	58.0	164.5	109.7	62.8	578.3
2002	176.5	57.7	157.2	111.0	62.8	565.2
2003	170.4	56.1	148.2	111.0	62.8	548.5
2004	164.4	55.4	154.2	111.0	108.2	593.2
2005	159.3	54.6	162.6	111.0	126.6	614.1
2006	155.3	53.7	168.3	111.0	116.8	605.1
2007	150.8	52.8	185.3	109.8	149.3	648.0
2008	146.4	52.8	207.2	104.4	160.1	670.9

SOURCE: Canadian Energy Research Institute.

^aTotals include volumes utilized as feedstock to the Coop and Lloydminster Upgraders.

TABLE D.5b
DETAILED PRODUCTION PROFILE SUMMARY
ALL ECONOMIC SOURCES
(MMb/yr.)

Year	Light/Medium Conventional Oil		Heavy Oil		Synthetic Crude Oil	
	Discovered	Undiscovered	Discovered	Undiscovered	Existing Expansion	Coop OSLO Upgrader Lloydminster Upgrader
1988	290.0	63.4	69.0	9.3	70.0	7.8
1989	254.0	73.3	61.0	14.2	76.0	15.6
1990	223.0	81.4	54.0	19.0	79.0	15.6
1991	198.0	88.0	47.0	23.4	79.0	15.6
1992	176.0	93.9	42.0	27.5	81.0	15.6
1993	159.0	99.2	37.0	31.2	81.0	15.6
1994	139.0	103.8	32.0	34.4	81.0	15.6
1995	123.0	107.5	29.0	37.3	81.0	15.6
1996	111.0	110.7	25.0	39.7	81.0	15.6
1997	99.0	113.6	21.0	41.8	81.0	15.6
1998	89.0	116.0	18.0	43.6	81.0	15.6
1999	80.0	117.7	15.0	45.1	81.0	15.6
2000	72.0	118.8	13.0	46.2	78.0	19.7
2001	64.0	119.3	11.0	47.0	74.0	35.7
2002	57.0	119.6	10.0	47.7	65.0	47.3
2003	51.0	119.5	8.0	48.1	56.0	48.6
2004	45.0	119.4	7.0	48.4	56.0	48.6
2005	40.0	119.3	6.0	48.6	56.0	54.5
2006	36.0	119.2	5.0	48.7	56.0	63.0
2007	32.0	118.7	4.0	48.8	56.0	63.0
2008	28.0	118.3	4.0	48.8	56.0	63.0
					1.9	70.8

Continued on Next Page

TABLE D.5b Continued
ALL ECONOMIC SOURCES
(MMb/yr.)

Year	Bitumen		Beaufort		Hibernia	
	Existing	Cold Lake	Peace River	Discovered	Undiscovered	Discovered
1988	32.4	13.8	5.5			
1989	39.5	7.2				
1990	42.3	11.5				
1991	42.3	13.8	5.3			
1992	42.3	13.8	6.4			
1993	42.3	13.8	6.4			
1994	42.3	13.8	6.4			
1995	42.3	13.8	6.4			
1996	42.3	37.1	6.4			12.6
1997	42.3	40.8	6.4			45.7
1998	42.3	40.8	6.4			62.8
1999	42.3	40.8	6.4			62.8
2000	42.3	50.8	6.4			62.8
2001	42.3	60.9	6.4			62.8
2002	42.3	62.3	6.4			62.8
2003	42.3	62.3	6.4			62.8
2004	42.3	62.3	6.4	45.4		62.8
2005	42.3	62.3	6.4	63.8		62.8
2006	42.3	62.3	6.4	65.5		51.3
2007	42.3	62.3	5.3	65.5	40.2	43.6
2008	42.3	48.5	13.6	65.5	56.5	38.1

SOURCE: Canadian Energy Research Institute.



D.6 HIGH PRICE CASE
ALL MEGAPROJECTS



TABLE D.6a
PRODUCTION OF CRUDE OIL AND EQUIVALENT
ALL SOURCES
(MMb/yr.)

Year	Light/Medium Conventional	Heavy Oil ^a	Synthetic Crude	Bitumena	Frontier	Total
1988	355.5	78.9	77.8	51.7	0.0	563.9
1989	333.8	77.0	91.6	44.1	0.0	546.5
1990	315.6	76.1	94.6	49.3	0.0	535.6
1991	302.4	75.0	94.6	54.7	0.0	526.7
1992	291.4	70.0	96.6	54.4	0.0	512.4
1993	284.4	75.6	113.4	76.2	0.0	549.6
1994	273.4	75.1	114.1	78.4	0.0	541.0
1995	265.2	76.2	132.9	97.6	12.6	584.5
1996	260.2	75.7	153.1	109.6	45.7	644.3
1997	254.4	74.8	162.1	111.0	62.8	665.1
1998	249.8	74.6	173.8	111.0	62.8	672.0
1999	245.3	73.9	179.4	111.0	62.8	672.4
2000	240.6	73.8	190.1	117.5	62.8	684.8
2001	235.1	73.2	203.3	130.7	62.8	705.1
2002	230.0	73.4	203.3	136.7	62.8	706.2
2003	225.3	72.3	193.5	137.6	62.8	706.2
2004	220.7	72.1	193.5	137.8	108.2	732.3
2005	216.8	71.7	193.5	137.8	126.6	746.4
2006	213.7	71.2	199.2	137.8	206.4	828.3
2007	210.1	70.7	215.6	138.3	235.2	869.9
2008	206.6	71.0	238.1	134.7	233.0	883.4

SOURCE: Canadian Energy Research Institute.

^aTotals include volumes utilized as feedstock to the Coop and Lloydminster Upgraders.

TABLE D.6b
DETAILED PRODUCTION PROFILE SUMMARY
ALL ECONOMIC SOURCES
(MMb/yr.)

Year	Light/Medium Conventional Oil		Heavy Oil		Synthetic Crude Oil		
	Discovered	Undiscovered	Discovered	Undiscovered	Existing	Expansion	Coop OSLO Upgrader Lloydminster Upgrader
1988	290.0	65.5	69.0	9.9	70.0		7.8
1989	254.0	79.8	61.0	16.0	76.0		15.6
1990	223.0	92.6	54.0	22.1	79.0		15.6
1991	198.0	104.4	47.0	28.0	79.0		15.6
1992	176.0	115.4	42.0	33.5	81.0		15.6
1993	159.0	125.4	37.0	38.6	81.0		15.6
1994	139.0	134.4	32.0	43.1	81.0		15.6
1995	123.0	142.3	29.0	47.2	81.0		15.6
1996	111.0	149.2	25.0	50.7	81.0	2.8	15.6
1997	99.0	155.5	21.0	53.8	81.0	11.2	15.6
1998	89.0	160.8	18.0	56.6	81.0	19.2	15.6
1999	80.0	165.3	15.0	58.9	81.0	22.8	15.6
2000	72.0	168.6	13.0	60.8	78.0	24.9	15.6
2001	64.0	171.1	11.0	62.2	74.0	26.4	15.6
2002	57.0	173.0	10.0	63.4	65.0	27.6	15.6
2003	51.0	174.3	8.0	64.3	56.0	28.0	15.6
2004	45.0	175.6	7.0	65.1	56.0	28.0	15.6
2005	40.0	176.7	6.0	65.7	56.0	28.0	15.6
2006	36.0	177.7	5.0	66.2	56.0	33.7	15.6
2007	32.0	178.2	4.0	66.7	56.0	50.7	15.6
2008	28.0	178.7	4.0	67.0	56.0	70.8	15.6
					1.9		

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TABLE D.6b Continued

ALL ECONOMIC SOURCES
(MMb/yr.)

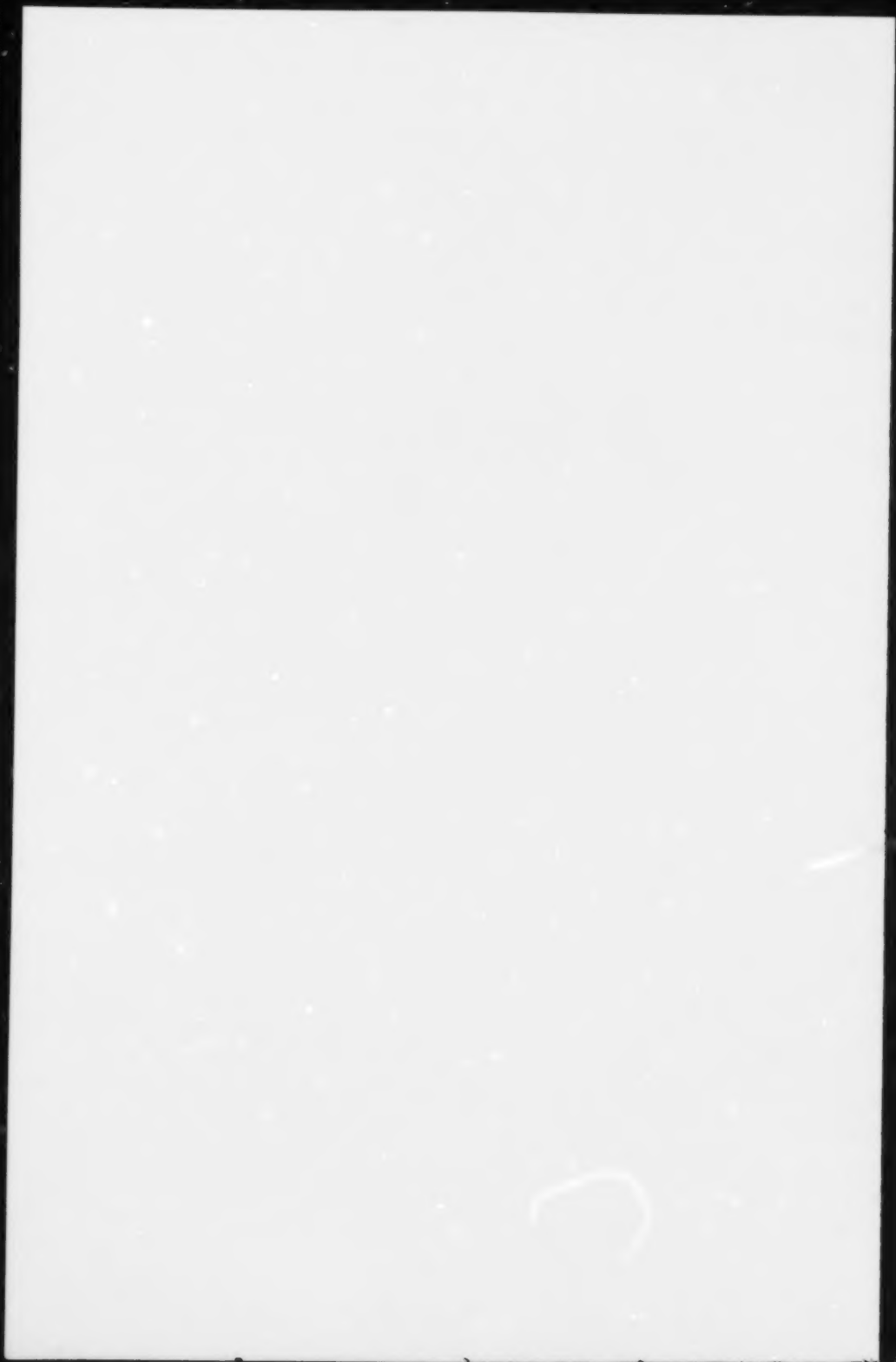
Year	Bitumen		Peace River	Beaufort		Hibernia
	Existing	Cold Lake		Discovered	Undiscovered	
1988	32.4	13.8	5.5			
1989	39.5	4.6				
1990	42.3	7.0				
1991	42.3	12.4				
1992	42.3	12.1				
1993	42.3	27.5	6.4			12.6
1994	42.3	29.6	6.4			45.7
1995	42.3	48.8	6.4			62.8
1996	42.3	60.9	6.4			62.8
1997	42.3	62.3	6.4			62.8
1998	42.3	62.3	6.4			62.8
1999	42.3	62.3	6.4			62.8
2000	42.3	62.3	12.9			62.8
2001	42.3	62.3	26.1			62.8
2002	42.3	62.3	32.2			62.8
2003	42.3	62.3	33.0			62.8
2004	42.3	62.3	33.2	45.4		62.8
2005	42.3	62.3	33.2	63.8	89.6	51.3
2006	42.3	62.3	33.2	65.5	126.1	43.6
2007	42.3	62.3	33.7	65.5	129.4	
2008	42.3	48.5	43.9	65.5		38.1

SOURCE: Canadian Energy Research Institute.



APPENDIX E**CANADIAN SUPPLY-DEMAND BALANCES**

- E.1 Low Price Case - Prudent Industrial Behaviour***
- E.2 Base Case - Prudent Industrial Behaviour***
- E.3 High Price Case - Prudent Industrial Behaviour***
- E.4 Base Case - Perfect Foresight***
- E.5 Base Case - All Megaprojects***
- E.6 High Price Case - All Megaprojects***



E.1 LOW PRICE CASE
PRUDENT INDUSTRIAL BEHAVIOUR



TABLE E.1a
CANADIAN CRUDE OIL SUPPLY-DEMAND BALANCES
ALL SOURCES
(MMb/yr.)

Year	Light Oil Production ^a	Heavy Blend Production ^b	Light Oil Demand	Heavy Blend Demand ^c	Net Exports		
					Light Oil	Heavy Blend	Total
1988	430.0	160.1	483.0	47.0	-53.0	113.1	60.1
1989	414.4	127.2	513.0	55.6	-98.6	71.6	-27.0
1990	389.6	108.8	553.0	56.4	-163.4	52.4	-111.0
1991	365.6	105.0	602.0	57.2	-236.4	47.8	-188.6
1992	346.0	106.7	652.0	57.9	-306.0	47.8	-258.2
1993	329.5	106.5	681.0	58.7	-351.5	47.8	-303.7
1994	310.2	108.8	696.0	59.5	-355.8	49.3	-336.5
1995	291.1	107.0	703.0	60.2	-407.9	46.8	-361.1
1996	284.2	104.0	704.0	60.9	-419.9	43.1	-376.8
1997	273.4	100.8	703.0	61.6	-429.6	39.2	-390.4
1998	264.6	119.4	698.0	62.2	-433.4	57.2	-376.2
1999	256.8	127.0	690.0	57.8	-433.2	69.2	-364.0
2000	246.5	125.8	684.0	63.4	-437.5	62.4	-375.1
2001	235.1	124.3	677.0	63.4	-441.9	60.9	-381.0
2002	219.5	123.9	670.0	63.4	-450.6	60.5	-390.1
2003	204.6	122.1	667.0	63.4	-462.4	58.7	-403.7
2004	230.8	121.4	662.0	63.5	-431.2	57.9	-373.3
2005	245.3	120.6	657.0	69.6	-412.0	51.0	-361.0
2006	236.5	119.7	651.0	70.9	-414.5	48.8	-365.7
2007	251.4	127.5	645.0	70.9	-393.6	56.6	-337.0
2008	269.6	131.5	639.0	86.9	-369.4	44.6	-324.8

SOURCE: Canadian Energy Research Institute.

^aLight oil production is the sum of Light/Medium Conventional, Synthetic Crude, and Frontier Crude from Table D.1a.
^bHeavy oil production includes diluent used for transport. Therefore, the heavy oil volumes are not directly comparable to the detailed production summary figures provided in Appendix D.
^cHeavy blend demand includes domestic end-use demand for bitumen and feedstock demand for the Coop and Lloydminster heavy oil upgraders.

TABLE E.1b
CANADIAN CONDENSATE BALANCE
(MMb/yr.)

Year	Condensate Supply	Additional Diluent	Total Supply	Disposition			
				EOR	Bitumen Blend	Heavy Oil Export	Crude Oil Pool
1988	44.4	8.5	52.9	14.5	25.8	12.6	
1989	46.0		46.0	13.8	19.8	10.4	2.1
1990	48.3		48.3	13.1	21.1	6.9	7.1
1991	50.6		50.6	12.4	21.1	6.3	10.7
1992	51.0		51.0	12.1	21.1	6.5	11.3
1993	51.3		51.3	11.7	21.1	6.6	11.9
1994	55.6		55.6	11.3	21.1	6.9	16.2
1995	61.7		61.7	10.7	21.1	6.6	23.2
1996	61.8		61.8	10.2	21.1	6.2	24.3
1997	61.8		61.8	9.7	21.1	5.7	25.2
1998	61.7		61.7	9.4	28.0	5.4	18.9
1999	58.6		58.6	9.1	31.3	5.1	13.2
2000	55.4		55.4	8.7	31.3	4.9	10.6
2001	53.2		53.2	8.6	31.3	4.7	8.7
2002	51.5	5.4	56.9	8.5	31.3	4.6	12.5
2003	49.5	20.8	70.3	8.3	31.3	4.3	26.4
2004	47.3	0.0	47.3	7.9	31.3	4.2	3.9
2005	44.3	0.0	44.3	7.5	31.3	4.1	1.4
2006	41.4	0.9	42.3	7.1	31.3	3.9	
2007	38.9	5.8	44.7	6.7	34.2	3.8	
2008	36.5	9.1	45.6	6.3	35.5	3.8	

SOURCE: Canadian Energy Research Institute.

E.2 BASE CASE
PRUDENT INDUSTRIAL BEHAVIOUR



TABLE E.2a
CANADIAN CRUDE OIL SUPPLY-DEMAND BALANCES
ALL SOURCES
(MMb/yr.)

Year	Light Oil Production ^a	Heavy Blend Production ^b	Light Oil Demand	Heavy Blend Demand ^c	Net Exports		
					Light Oil	Heavy Blend	Total
1988	431.2	160.7	483.0	46.8	-51.8	113.9	62.1
1989	418.9	140.4	500.0	55.6	-81.1	84.8	3.7
1990	399.0	148.4	522.0	56.4	-123.0	92.0	-31.0
1991	380.6	166.8	547.0	57.2	-166.4	99.6	-66.8
1992	366.5	157.5	572.0	57.9	-205.5	99.6	-105.9
1993	354.8	155.9	589.0	58.7	-234.2	97.2	-137.0
1994	339.4	153.8	600.0	59.5	-260.6	94.3	-166.3
1995	327.1	153.6	606.0	60.2	-278.9	93.4	-185.5
1996	318.3	166.2	608.0	60.9	-289.7	105.3	-184.4
1997	309.2	166.2	610.0	61.6	-300.8	104.6	-196.2
1998	303.8	161.9	612.0	66.1	-308.2	95.8	-212.4
1999	297.1	159.4	612.0	70.4	-314.9	89.0	-225.9
2000	288.5	156.6	611.0	77.9	-322.5	78.7	-243.8
2001	277.0	157.2	612.0	93.9	-335.0	63.3	-271.7
2002	264.4	156.8	611.0	109.9	-346.6	46.9	-299.7
2003	265.3	154.8	612.0	110.7	-346.7	44.1	-302.6
2004	320.6	153.0	610.0	115.0	-289.4	38.0	-251.4
2005	340.1	152.2	608.0	125.8	-267.9	26.4	-241.5
2006	356.8	152.0	606.0	126.4	-249.2	25.6	-223.6
2007	445.4	147.7	604.0	126.4	-158.6	21.3	-137.3
2008	497.7	137.0	599.0	126.4	-101.3	10.6	-90.7

SOURCE: Canadian Energy Research Institute.

^aLight oil production is the sum of Light/Medium Conventional, Synthetic Crude, and Frontier Crude from Table D.2a.

^bHeavy oil production includes diluent used for transport. Therefore, the heavy oil volumes are not directly comparable to the detailed production summary figures provided in Appendix D.

^cHeavy blend demand includes domestic end-use demand for bitumen and feedstock demand for the Coop and Lloydminster heavy oil upgraders.

TABLE E.2b
CANADIAN CONDENSATE BALANCE
(MMb/yr.)

Year	Condensate Supply	Additional Diluent	Total Supply	Disposition			
				EOR	Bitumen Blend	Heavy Oil Export	Crude Oil Pool
1988	44.4	8.6	53.0	14.5	25.8	12.7	
1989	46.0	1.9	47.9	13.8	23.4	10.7	
1990	48.3	2.0	50.3	13.1	26.9	10.3	
1991	50.6	2.4	53.0	12.4	30.7	9.9	
1992	51.0	2.1	53.1	12.1	31.3	9.7	
1993	51.3	1.1	52.4	11.7	31.3	9.5	
1994	55.6		55.6	11.3	31.3	9.1	3.9
1995	61.7		61.7	10.7	31.3	9.1	10.6
1996	61.8		61.8	10.2	36.1	8.8	6.7
1997	61.8		61.8	9.7	36.8	8.5	6.8
1998	61.7		61.7	9.4	36.4	8.0	7.9
1999	58.6		58.6	9.1	36.3	7.7	5.5
2000	55.4		55.4	8.7	36.0	7.4	3.3
2001	53.2		53.2	8.6	36.7	7.2	0.7
2002	51.5	1.2	52.7	8.5	37.4	6.8	
2003	49.5	4.7	54.2	8.3	41.1	4.8	
2004	47.3	8.0	55.3	7.9	44.5	3.0	
2005	44.3	11.3	55.6	7.5	45.9	2.2	
2006	41.4	14.0	55.4	7.1	46.2	2.0	
2007	38.9	14.8	53.7	6.7	45.1	1.9	
2008	36.5	13.2	49.7	6.3	41.6	1.9	

SOURCE: Canadian Energy Research Institute.

E.3 HIGH PRICE CASE
PRUDENT INDUSTRIAL BEHAVIOUR



TABLE E.3a
CANADIAN CRUDE OIL SUPPLY-DEMAND BALANCES
ALL SOURCES
(MMb/yr.)

Year	Light Oil Production ^a	Heavy Blend Production ^b	Light Oil Demand	Heavy Blend Demand ^c	Net Exports	
					Light Oil	Heavy Blend
1988	434.4	161.4	475.0	47.1	-40.6	114.3
1989	425.4	138.6	492.0	55.6	-66.6	83.0
1990	410.2	145.3	511.0	56.4	-100.8	88.9
1991	397.0	152.2	535.0	57.2	-138.0	95.0
1992	388.0	152.4	557.0	57.9	-169.0	94.5
1993	381.0	153.1	572.0	58.7	-191.0	94.4
1994	375.1	157.4	581.0	75.5	-205.9	81.9
1995	367.8	157.5	586.0	92.2	-218.2	65.3
1996	378.7	168.1	588.0	97.7	-207.3	70.4
1997	385.4	177.0	587.0	106.6	-201.6	70.4
1998	396.7	165.3	586.0	116.5	-189.3	48.8
1999	399.4	159.4	585.0	120.8	-185.6	38.6
2000	396.2	153.9	583.0	126.8	-186.8	27.0
2001	386.7	153.8	582.0	137.3	-195.3	16.5
2002	374.4	153.6	581.0	153.3	-206.6	0.3
2003	370.2	152.4	580.0	156.7	-209.8	-4.3
2004	426.8	150.7	579.0	156.7	-152.2	-6.0
2005	445.5	150.2	576.0	156.7	-133.5	-6.5
2006	553.0	149.6	574.0	156.7	-21.0	-7.1
2007	638.7	150.0	569.0	156.7	69.7	-6.7
2008	678.9	144.9	564.0	156.7	114.9	-11.8
						103.1

SOURCE: Canadian Energy Research Institute.

^aLight oil production is the sum of Light/Medium Conventional, Synthetic Crude, and Frontier Crude from Table D.3a.

^bHeavy oil production includes diluent used for transport. Therefore, the heavy oil volumes are not directly comparable to the detailed production summary figures provided in Appendix D.

^cHeavy blend demand includes domestic end-use demand for bitumen and feedstock demand for the Coop and Lloydminster heavy oil upgraders.

TABLE D.3b
CANADIAN CONDENSATE BALANCE
(MMb/yr.)

Year	Condensate Supply	Additional Diluent	Total Supply	Disposition			
				EOR	Bitumen Blend	Heavy Oil Export	Crude Oil Pool
1988	44.4	8.7	53.1	14.5	25.8	12.8	
1989	46.0	0.9	46.9	13.8	22.0	11.1	
1990	48.3	0.3	48.6	13.1	24.7	10.9	
1991	50.6		50.6	12.4	27.4	10.7	0.1
1992	51.0		51.0	12.1	27.2	10.8	
1993	51.3		51.3	11.7	27.5	10.8	
1994	55.6		55.6	11.3	30.2	10.2	0.4
1995	61.7		61.7	10.7	30.1	10.3	2.2
1996	61.8		61.8	10.2	37.5	8.5	0.8
1997	61.8		61.8	9.7	43.7	7.0	0.4
1998	61.7		61.7	9.4	43.6	5.3	3.1
1999	58.6		58.6	9.1	43.5	4.4	1.5
2000	55.4		55.4	8.7	42.8	3.9	
2001	53.2	2.2	55.4	8.6	43.0	3.8	
2002	51.5	3.9	55.4	8.5	43.3	3.6	
2003	49.5	6.7	56.2	8.3	47.9	0.0	
2004	47.3	10.0	57.3	7.9	49.4	0.0	
2005	44.3	13.0	57.0	7.5	49.9	0.0	
2006	41.4	15.5	56.9	7.1	49.8	0.0	
2007	38.9	17.8	56.7	6.7	50.0	0.0	
2008	36.5	18.0	54.5	6.3	48.2	0.0	

SOURCE: Canadian Energy Research Institute.

**E.4 BASE CASE
PERFECT FORESIGHT**



TABLE E.4a
CANADIAN CRUDE OIL SUPPLY-DEMAND BALANCES
ALL SOURCES
(MMb/vt.)

Year	Light Oil Production ^a	Heavy Blend Production ^b	Light Oil Demand	Heavy Blend Demand ^c	Net Exports		Total
					Light Oil	Heavy Blend	
1988	431.2	160.7	483.0	47.1	-51.8	113.6	61.8
1989	418.9	140.4	500.0	55.6	-81.1	64.8	3.7
1990	399.0	148.4	522.0	56.4	-123.0	92.0	-31.0
1991	380.6	156.8	547.0	57.2	-166.4	99.6	-66.8
1992	366.5	157.5	572.0	57.9	-205.5	99.6	-105.9
1993	354.8	155.9	589.0	58.7	-234.2	97.2	-137.0
1994	339.4	153.8	600.0	59.5	-260.6	94.3	-166.3
1995	327.1	153.6	606.0	60.2	-278.9	93.4	-185.5
1996	318.3	166.2	608.0	74.9	-289.7	91.3	-198.4
1997	314.9	168.8	610.0	75.6	-295.1	93.2	-201.9
1998	334.7	166.8	612.0	90.8	-277.3	76.0	-201.3
1999	367.2	161.5	612.0	107.4	-244.8	54.1	-190.7
2000	465.2	154.6	611.0	113.3	-145.8	41.3	-104.5
2001	527.3	152.7	612.0	113.3	-84.7	39.4	-45.3
2002	555.7	152.4	611.0	118.3	-55.3	34.1	-21.2
2003	574.4	150.6	612.0	126.4	-37.6	24.2	-13.4
2004	602.6	142.0	610.0	126.4	-7.4	15.6	8.2
2005	634.4	129.6	608.0	126.4	26.4	3.2	29.6
2006	658.7	128.9	606.0	126.4	52.7	2.5	55.2
2007	718.7	126.0	604.0	126.4	114.7	-0.4	114.3
2008	740.6	117.9	599.0	126.4	141.6	-8.5	133.1

SOURCE: Canadian Energy Research Institute.

^aLight oil production is the sum of Light/Medium Conventional, Synthetic Crude, and Frontier Crude from Table D.4a.
^bHeavy oil production includes diluent used for transport. Therefore, the heavy oil volumes are not directly comparable to the detailed production summary figures provided in Appendix D.
^cHeavy blend demand includes domestic end-use demand for bitumen and feedstock demand for the Coop and Lloydminster heavy oil upgraders.

TABLE E.4b
CANADIAN CONDENSATE BALANCE
(MMb/yr.)

Year	Condensate Supply	Additional Diluent	Total Supply	Disposition			
				EOR	Bitumen Blend	Heavy Oil Export	Crude Oil Pool
1988	44.4	8.6	53.0	14.5	25.8	12.7	
1989	46.0	1.9	47.9	13.8	23.4	10.7	
1990	48.3	2.0	50.3	13.1	26.9	10.3	
1991	50.6	2.4	53.0	12.4	30.7	9.9	
1992	51.0	2.1	53.1	12.1	31.3	9.7	
1993	51.3	1.1	52.4	11.7	31.3	9.5	
1994	55.6		55.6	11.3	31.3	9.1	3.9
1995	61.7		61.7	10.7	31.3	9.1	10.6
1996	61.8		61.8	10.2	36.1	8.8	6.7
1997	61.8		61.8	9.7	37.7	8.5	5.9
1998	61.7		61.7	9.4	39.9	7.2	5.2
1999	58.6		58.6	9.1	39.7	6.5	3.3
2000	55.4		55.4	8.7	41.5	4.6	0.6
2001	53.2	3.1	56.3	8.6	45.0	2.7	
2002	51.5	5.0	56.5	8.5	45.5	2.4	
2003	49.5	6.5	56.0	8.3	45.6	2.1	
2004	47.3	6.3	53.6	7.9	45.3	0.4	
2005	44.3	6.1	50.4	7.5	42.6	0.3	
2006	41.4	8.5	49.9	7.1	42.6	0.1	
2007	38.9	9.8	48.7	6.7	42.0	0.0	
2008	36.5	9.1	45.6	6.3	39.3	0.0	

SOURCE: Canadian Energy Research Institute.

**E.5 BASE CASE
ALL MEGAPROJECTS**

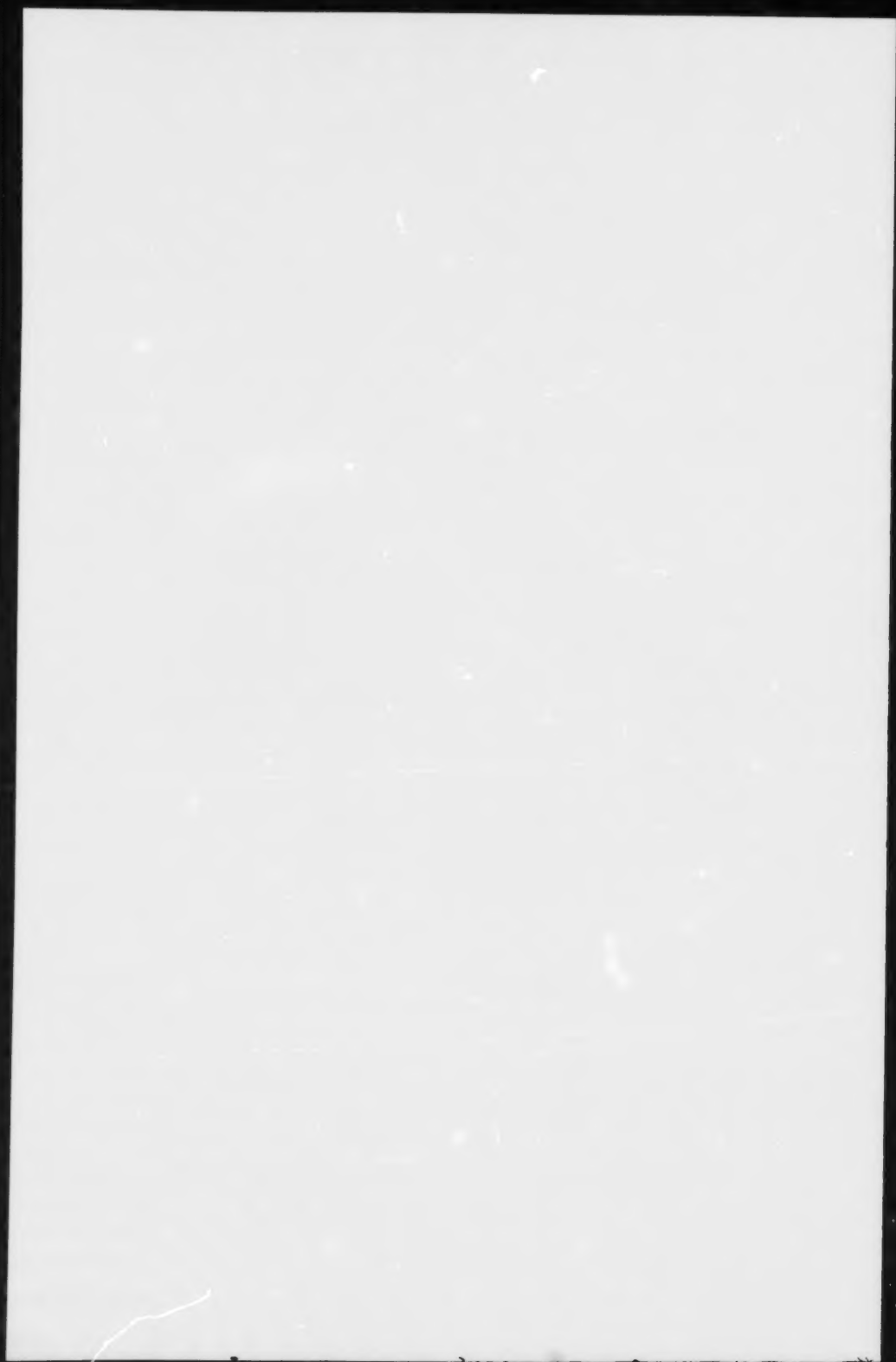


TABLE E.5a
CANADIAN CRUDE OIL SUPPLY-DEMAND BALANCES
ALL SOURCES
(MMb/yr.)

Year	Light Oil Production ^a	Heavy Blend Production ^b	Light Oil Demand	Heavy Blend Demand ^c	Net Exports		Total
					Light Oil	Heavy Blend	
1988	431.2	160.7	483.0	47.1	-51.8	113.6	61.8
1989	418.9	140.4	500.0	55.6	-81.1	84.8	3.7
1990	399.0	148.4	522.0	56.4	-123.0	92.0	-31.0
1991	380.6	156.8	547.0	57.2	-166.4	99.6	-66.8
1992	366.5	157.5	572.0	57.9	-205.5	99.6	-105.9
1993	371.6	133.8	589.0	74.7	-217.4	59.1	-188.3
1994	346.7	131.7	600.0	75.5	-253.3	56.2	-197.1
1995	359.3	131.6	606.0	76.2	-246.7	55.4	-191.3
1996	392.0	164.7	608.0	76.9	-216.0	87.8	-128.2
1997	413.0	167.9	610.0	77.6	-197.0	90.3	-106.7
1998	403.9	166.5	612.0	79.4	-208.1	87.1	-121.0
1999	401.7	160.9	612.0	82.9	-210.3	78.0	-132.3
2000	409.2	154.1	611.0	86.9	-201.8	67.2	-134.6
2001	410.6	152.6	612.0	102.9	-201.4	49.7	-151.7
2002	396.5	152.4	611.0	111.1	-214.5	41.3	-173.2
2003	381.4	150.6	612.0	111.1	-230.6	39.5	-191.1
2004	426.8	142.0	610.0	115.0	-183.2	27.0	-156.2
2005	448.5	129.9	608.0	125.8	-159.5	4.1	-155.4
2006	440.4	128.9	606.0	126.4	-165.6	2.5	-163.1
2007	485.4	126.0	604.0	126.4	-118.6	-0.4	-119.0
2008	513.7	117.9	599.0	126.4	-85.3	-8.5	-93.8

SOURCE: Canadian Energy Research Institute.

^aLight oil production is the sum of Light/Medium Conventional, Synthetic Crude, and Frontier Crude from Table D.5a.

^bHeavy oil production includes diluent used for transport. Therefore, the heavy oil volumes are not directly comparable to the detailed production summary figures provided in Appendix D.

^cHeavy blend demand includes domestic end-use demand for bitumen and feedstock demand for the Coop and Lloydminster heavy oil upgraders.

TABLE E.5b
CANADIAN CONDENSATE BALANCE
(MMb/yr.)

Year	Condensate Supply	Additional Diluent	Total Supply	Disposition			
				EOR	Bitumen Blend	Heavy Oil Export	Crude Oil Pool
1988	44.4	8.6	53.0	14.5	25.8	12.7	
1989	46.0	1.9	47.9	13.8	23.4	10.7	
1990	48.3	2.0	50.3	13.1	26.9	10.3	
1991	50.6	2.4	53.0	12.4	30.7	9.9	
1992	51.0	2.1	53.1	12.1	31.3	9.7	
1993	51.3		51.3	11.7	27.8	7.7	4.1
1994	55.6		55.6	11.3	27.8	7.4	9.1
1995	61.7		61.7	10.7	27.8	7.3	15.8
1996	61.8		61.8	10.2	39.5	7.1	5.1
1997	61.8		61.8	9.7	41.3	6.7	4.1
1998	61.7		61.7	9.4	41.3	6.5	4.5
1999	58.6		58.6	9.1	40.7	5.9	2.9
2000	55.4		55.4	8.7	42.5	4.1	0.2
2001	53.2	3.2	56.4	8.6	45.1	2.6	
2002	51.5	5.0	56.5	8.5	45.5	2.4	
2003	49.5	6.5	56.0	8.3	45.5	2.1	
2004	47.3	6.3	53.6	7.9	44.3	1.4	
2005	44.3	6.1	50.4	7.5	43.6	0.4	
2006	41.4	8.5	49.9	7.1	42.6	0.1	
2007	38.9	9.8	48.7	6.7	42.0	0.0	
2008	36.5	9.1	45.6	6.3	39.3	0.0	

SOURCE: Canadian Energy Research Institute.

E.6 HIGH PRICE CASE
ALL MEGAPROJECTS



TABLE E.6a
CANADIAN CRUDE OIL SUPPLY-DEMAND BALANCES
ALL SOURCES
(MMb/yr.)

Year	Light Oil Production ^a	Heavy Blend Production ^b	Light Oil Demand	Heavy Blend Demand ^c	Net Exports		
					Light Oil	Heavy Blend	Total
1988	433.3	161.4	475.0	47.1	-41.7	114.3	72.6
1989	425.4	138.6	492.0	55.6	-66.6	83.0	16.4
1990	410.2	145.3	511.0	56.4	-100.8	88.9	-11.9
1991	397.0	152.2	535.0	57.2	-138.0	95.0	-43.0
1992	388.0	152.4	557.0	57.9	-169.0	94.5	-74.5
1993	397.8	163.1	572.0	74.7	-174.2	88.4	-85.8
1994	387.5	164.8	581.0	82.1	-193.5	82.7	-110.8
1995	410.7	173.8	586.0	98.8	-175.3	75.0	-100.3
1996	459.0	176.0	586.0	102.6	-127.0	73.4	-53.6
1997	479.3	175.7	587.0	107.2	-107.7	68.5	-39.2
1998	486.4	164.8	586.0	116.5	-99.6	48.3	-51.3
1999	487.5	169.3	585.0	120.8	-97.5	38.5	-59.0
2000	493.5	153.7	583.0	126.9	-89.5	26.8	-62.7
2001	501.2	151.2	582.0	137.4	-80.8	13.8	-67.0
2002	496.1	150.5	581.0	153.4	-84.9	-2.9	-87.8
2003	481.6	150.2	580.0	156.7	-98.4	-6.5	-104.9
2004	522.4	150.2	579.0	156.7	-56.6	-6.5	-63.1
2005	536.9	149.8	576.0	156.7	-39.1	-6.9	-46.0
2006	619.3	149.2	574.0	156.7	45.3	-7.5	37.8
2007	660.9	150.0	569.0	156.7	91.9	-6.7	85.2
2008	677.7	144.3	564.0	143.1	113.7	1.2	114.9

SOURCE: Canadian Energy Research Institute.

^aLight oil production is the sum of Light/Medium Conventional, Synthetic Crude, and Frontier Crude from Table D.6a.

^bHeavy oil production includes diluent used for transport. Therefore, the heavy oil volumes are not directly comparable to the detailed production summary figures provided in Appendix D.

^cHeavy blend demand includes domestic end-use demand for bitumen and feedstock demand for the Coop and Lloydminster heavy oil upgraders.

TABLE E.6b
CANADIAN CONDENSATE BALANCE
(MMb/yr.)

Year	Condensate Supply	Additional Diluent	Total Supply	Disposition			
				EOR	Bitumen Blend	Heavy Oil Export	Crude Oil Pool
1988	44.4	8.7	53.1	14.5	25.8	12.8	
1989	46.0	0.9	46.9	13.8	22.0	11.1	
1990	48.3	0.3	48.6	13.1	24.7	10.9	
1991	50.6	0.0	50.6	12.4	27.4	10.7	0.1
1992	51.0	0.0	51.0	12.1	27.2	10.8	0.9
1993	51.3	4.1	55.4	11.7	34.7	9.0	
1994	55.6	0.1	55.7	11.3	35.6	8.8	
1995	61.7		61.7	10.7	41.9	7.3	0.1
1996	61.8		61.8	10.2	45.5	6.0	0.4
1997	61.8		61.8	9.7	46.0	5.7	0.4
1998	61.7		61.7	9.4	44.4	4.8	3.1
1999	58.6		58.6	9.1	43.6	4.3	1.5
2000	55.4	0.7	56.1	8.7	44.4	3.0	
2001	53.2	4.3	57.5	8.6	47.7	1.2	
2002	51.5	6.6	58.1	8.5	49.6	0.0	
2003	49.5	8.6	58.1	8.3	49.8	0.0	
2004	47.3	10.4	57.7	7.9	49.8	0.0	
2005	44.3	13.0	57.3	7.5	49.8	0.0	
2006	41.4	15.4	56.8	7.1	49.7	0.0	
2007	38.9	17.8	56.7	6.7	50.0	0.0	
2008	36.5	17.9	54.4	6.3	47.1	1.0	

SOURCE: Canadian Energy Research Institute.

APPENDIX F**MEGAPROJECT EVALUATIONS**

F.1 OSLO Integrated Mined Oil Sands Plant

F.2 Hibernia

F.3 Lloydminster Upgrader



Appendix F

MEGAPROJECT EVALUATIONS

This appendix contains the detailed cash flow projections undertaken for each of the proposed megaprojects. Detailed tables supporting the project analyses are presented following the text.

F.1 OSLO Integrated Mined Oil Sands Plant

F.1.1 Assumptions

OSLO project ownership is described in the press release documentation to the Agreement as:

Esso Resources Canada Ltd.	25%
Canadian Occidental Petroleum Ltd.	20%
Gulf Canada Resources Ltd.	20%
Petro-Canada Inc.	15%
Pan-Canadian Petroleum Ltd.	10%
Alberta Oil Sands Equity	<u>10%</u>
	100%

The proposed project location is approximately 40 kilometres northeast of the Syncrude plant, on Lease 31. The overburden on the lease is estimated to average 18 metres with an assumed waste-to-ore ratio of 0.43. The average bitumen content is 11.2 percent, yielding mineable reserves of 3.5 billion barrels.

The mining technologies proposed for the project are trucking and shovels, a bucket wheel excavator, dragline, and bucket wheel exclaimer. The proposed extraction process is OSLO cold water extraction, which will necessitate construction of a tailings pond. The upgrading process is to be a high yield hydrogen addition process.

Plant capacity of 77,000 barrels per day is expected from an upfront capital expenditure of \$4.1 billion. Operating costs are projected to be \$400 million (in 1988 \$Cdn.) per year with an additional \$40 million of required sustaining capital expenditure per year. In order to estimate the likely returns to the public sector and the project owners, capital expenditure scenarios have been generated and the shares of these expenditures allocated to the two groups.

The basic project assumptions are summarized in Table F.1a.

F.1.2 Project Analysis

Table F.1b provides a summary of the likely break-even crude oil prices for the OSLO project, given the assumptions provided above. The various discount rates represent the rate of return to the project given the prices calculated under the total column. The range of break-even prices is from \$17.73 per barrel under 0 rate of return to \$42.46 per barrel under 15 percent rate of return (all rate of return figures expressed in real terms, corrected for inflation).

Tables F.1c and F.1d provide an analysis of cash flow to the public sector and project owners, respectively. The public sector analysis includes revenues and contributions for both the federal and provincial governments. The analysis assumes the base case crude oil projections used in this study.

F.2 Hibernia

F.2.1 Assumptions

Background assumptions for the financial analysis of the Hibernia project are provided in Table F.2a. Front-end capital expenditures of \$5.3 billion are incurred over the period 1989 to 1994. Peak oil production of 40.2 million barrels per year is reached in 1997 and maintained for 9 years. Total production is estimated at 533 million barrels. Table F.2b provides a summary of the public sector financing arrangements for the project.

F.2.2 Financial Analysis

Table F.2c provides a summary of the likely break-even crude oil prices for the Hibernia project, given the assumptions provided above. The various discount rates represent the rate of return to the project given the crude oil prices provided in the total column. The range is from \$21.20 per barrel under a zero rate of return, to \$37.10 per barrel under a 12 percent rate of return (all rate of return figures expressed in real terms, corrected for inflation). Table F.2d provides a summary of cash flow to the public sector and project owners, based on the preceding information.

F.3 Lloydminster Upgrader

F.3.1 Project Assumptions

The Lloydminster Upgrader, often referred to as the Husky Upgrader or Bi-provincial Upgrader, is expected to produce 46,000 barrels of synthetic crude per day. This upgrader is designed to take a feedstock of both heavy oil and bitumen, and requires natural gas for heating and for a hydrogen source.

The capital cost of the project is expected to be approximately \$1,267 million, including \$100 million already spent by Husky Oil. These capital expenditures are to be divided among the participants, namely Husky Oil and the governments of Saskatchewan, Alberta and Canada. The rates of participation are outlined in Section 6.3.1. The agreement structure resembles a typical industry farm-in arrangement where one party, in this case Husky, receives a higher percentage of the revenue stream until payout.

In order to analyse the economics of this project, certain assumptions were made regarding the operations and pricing of the upgrader components. Three different cases are presented in this appendix.

F.3.2 Base Case Prices

In each case, assumptions have been made regarding western Canadian light crude prices, condensate prices, heavy oil and bitumen prices. Presented in Table F.3a are prices for heavy oil blend, bitumen blend and natural gas. These prices provide a basis for calculating feedstock costs as presented in Table F.3b.

One of the key assumptions concerns the rate at which the light/heavy price differential changes. The base case assumption in the model assumes that the differential (calculated in Chicago) begins at \$4.00 per barrel and, beginning in 1990, increases by \$0.25 per barrel per year until reaching \$8.00 per barrel by 2005. Since the impact of changing the differential is subsequently netted back to western Canada, this will have an effect on the heavy oil and bitumen prices presented below, and on the operating cost and revenue calculations provided in Table F.3c.

In Table F.3d, cash flows to each participant are analysed in order to determine when the payout thresholds are reached. The total

cash flows and internal rates of return for each of the participants are then calculated and presented in Table F.3e.

F.3.3 Minimum Bitumen Price

Using the low price case, a scenario was run which also assumed a likely minimum bitumen price of \$6.00 per barrel. The rationale behind this minimum price was that bitumen probably would not be produced for less, even in the short run. Table F.3f contains the liquid hydrocarbon prices used in the run.

Table F.3g contains operating costs and cash flows in nominal dollars and includes a per barrel gross profit from the cash flow to each participant, based upon these assumptions. These results show that the economics of the upgrader are greatly dependant upon the light/heavy crude oil price differential, rather than on the absolute level of the prices. The minimum bitumen price will have reduced the differential slightly and caused a slightly lower internal rate of return for the participants. Notice, however, that Saskatchewan's return is slightly higher in this case.

F.3.4 Constant Differential Case

The difference between the price of light or synthetic crude and heavier crudes and bitumen determines the economics of the upgrader. The constant differential case demonstrates this by using base case oil prices and keeping a constant \$4.00 (U.S.) differential between light and heavy oil.

The price assumptions for this case are presented in Table F.3h. Table F.3i contains the operating, capital and feedstock costs together with net operating revenue. Table F.3j contains the internal rate of return calculations and cash flow to each participant.

In Table F.3j the internal rates of return have fallen substantially in comparison to either of the cases which assumed increasing differentials. Clearly, differentials will determine the profitability of this project unless independent prices are set for inputs of heavy oil or bitumen feedstocks.

F.1 OSLO INTEGRATED MINED OIL SANDS PLANT

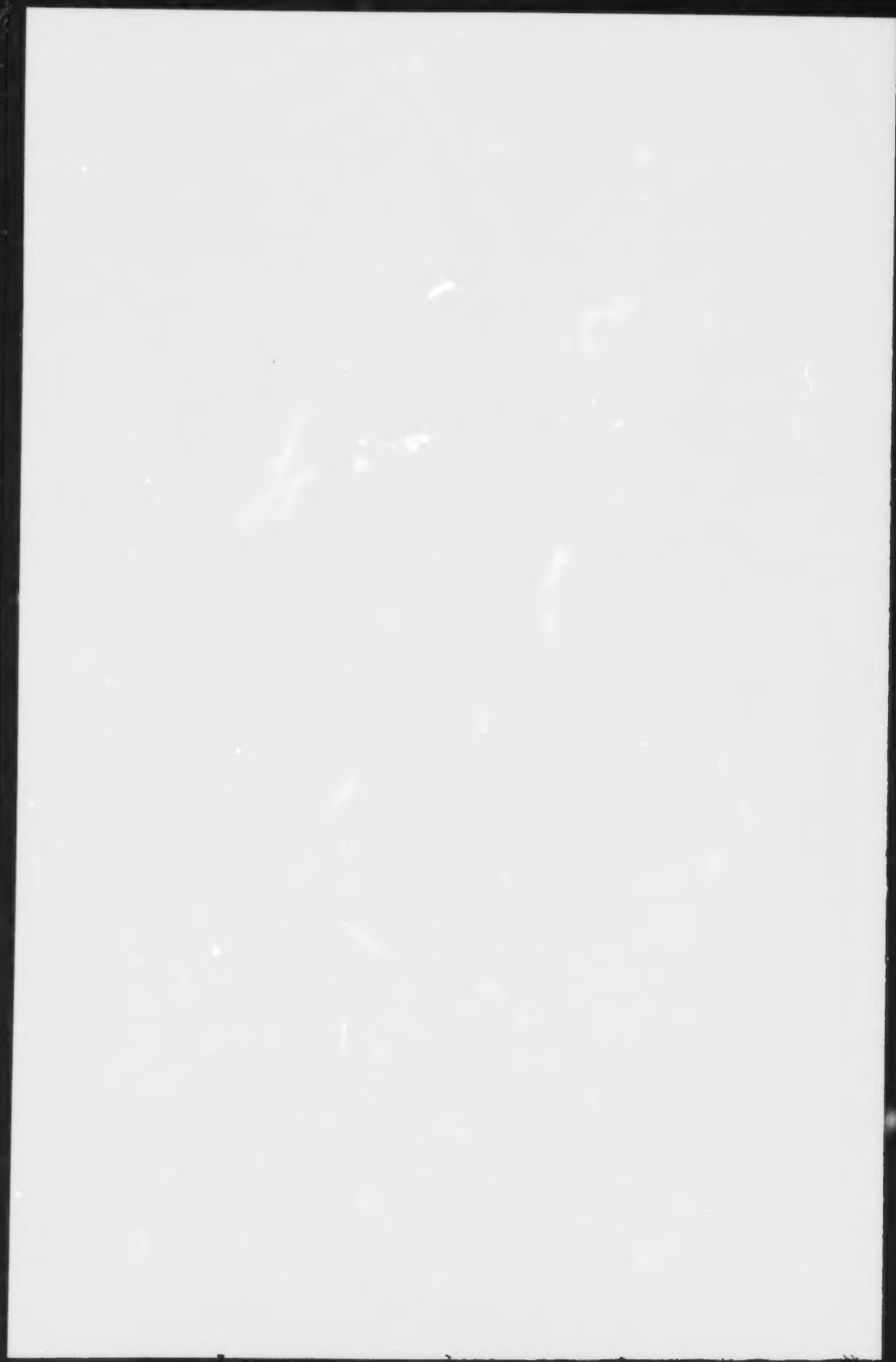


TABLE F.1a
OSLO PROJECT ASSUMPTIONS

Year	Production (MMb/yr.)	Capital Expenditure (1988 MM \$Cdn.)	Operating Costs (1988 MM \$Cdn.)	Royalty ^a (1988 MM \$Cdn.)
1988	0	0.00	0.00	0.00
1989	0	0.00	0.00	0.00
1990	0	76.00	0.00	0.00
1991	0	265.00	0.00	0.00
1992	0	476.00	0.00	0.00
1993	0	1,005.00	0.00	0.00
1994	0	734.00	0.00	0.00
1995	0	387.00	0.00	0.00
1996	7	367.00	360.00	2.00
1997	18	40.00	360.00	6.00
1998	25	40.00	360.00	16.00
1999	28	40.00	360.00	19.00
2000	28	40.00	400.00	29.00
2001	28	40.00	400.00	30.00
2002	28	40.00	400.00	41.00
2003	28	40.00	400.00	42.00
2004	28	40.00	400.00	54.00
2005	28	40.00	400.00	56.00
2006	28	40.00	400.00	58.00
2007	28	40.00	400.00	168.00
2008	28	40.00	400.00	177.00
2009	28	40.00	400.00	177.00
2010	28	40.00	400.00	177.00
2011	28	40.00	400.00	177.00
2012	28	40.00	400.00	153.00
2013	28	40.00	400.00	211.00
2014	28	40.00	400.00	253.00
2015	28	40.00	400.00	253.00
2016	28	40.00	400.00	253.00
2017	28	40.00	400.00	253.00
2018	28	40.00	400.00	253.00
2019	28	40.00	400.00	253.00
2020	28	40.00	400.00	253.00
2021	28	40.00	400.00	253.00
2022	28	40.00	400.00	253.00
2023	28	40.00	400.00	253.00
2024	28	40.00	360.00	265.00
2025	28	40.00	360.00	265.00
2026	28	40.00	360.00	265.00
2027	28	40.00	360.00	265.00
2028	28	40.00	360.00	265.00
2029	28	40.00	360.00	265.00
2030	28	40.00	360.00	265.00

SOURCE: Canadian Energy Research Institute.

^aRoyalty estimates developed assuming base case crude oil price projection.

TABLE F.1b
OSLO PROJECT ECONOMICS

Discount Rate (%)	Discounted Aggregate Values			Per Barrel Values		
	Capital (MM \$Cdn.)	Operating Costs (MM \$Cdn.)	Production Volumes (MMb)	Capital Charges (\$ Cdn.)	Operating Cost (\$ Cdn.)	Discounted Royalty (\$ Cdn.)
0	3,278.70	13,560	949.8	3.45	14.28	17.73
5	3,733.60	6,666	450.1	8.29	14.81	23.10
7	3,931.30	5,362	265.7	11.03	15.04	26.06
10	4,245.90	4,089	265.7	15.98	15.39	31.36
12	4,468.20	3,518	225.2	19.84	15.62	35.47
15	4,821.70	2,908	182.0	26.49	15.98	42.46

SOURCE: Canadian Energy Research Institute.

TABLE F.1c
OSLO PUBLIC SECTOR CASH FLOW ANALYSIS
(millions of current \$Cdn.)

Year	Development Incentive Grant	Indexed Grant	Loan Guarantees	Pre-Production Interest Assistance	Post-Production Interest Assistance	Loan Repayment
1988	0	0	0	0	0	0
1989	0	0	0	0	0	0
1990	-21	-3	-31	0	0	0
1991	-75	-7	-112	-3	0	0
1992	-140	-3	-211	-12	0	0
1993	-309		-463	-30	0	0
1994	-235		-352	-69	0	0
1995	-71		-32	-99	0	0
1996				-38	0	0
1997					-2	0
1998						0
1999						197
2000						194
2001						191
2002						189
2003						194
2004						213
2005						233
2006						256
2007						260
2008						307
2009						320
2010						333
2011						347
2012						362
2013						
2014						
2015						
2016						
2017						
2018						
2019						
2020						
2021						
2022						
2023						

Continued On Next Page

TABLE F.1c Continued

Year	Temporary Financing Facility	Interest Assistance Repayment	Government Share of Net Project Income	Government Net Cash Flow	Royalty and Tax Revenue
1988	0	0	0	0	0
1989	0	0	0	0	0
1990	0	0	0	-54	-54
1991	0	0	0	-197	-197
1992	0	0	0	-366	-366
1993	0	0	0	-801	-801
1994	0	0	0	-655	-655
1995	0	0	0	-202	-202
1996	0	0	-13	-51	-180
1997	-125	0	32	-95	5
1998	125	0	63	188	455
1999		0	66	262	548
2000		0	66	260	564
2001		0	74	265	613
2002		0	81	270	675
2003		0	90	284	739
2004		0	97	309	824
2005		0	106	339	905
2006		0	115	371	995
2007		0	105	385	1202
2008		0	114	421	1319
2009		0	119	438	1375
2010		0	123	456	1434
2011		0	128	475	1496
2012		0	116	730	1649
2013		252	164	164	1494
2014			160	160	1616
2015			166	166	1685
2016			173	173	1757
2017			180	180	1832
2018			187	187	1911
2019			195	195	1992
2020			203	203	2077
2021			205	205	2197
2022			214	214	2290
2023			222	222	2386

SOURCE: Canadian Energy Research Institute.

TABLE F.1d
OWNERS NET CASH FLOW ANALYSIS

Year	GNP Deflator	Production Profile (MMbtyr.)	Operating Cost (MM \$Cdn.)	Owners Equity (MM \$Cdn.)	After Tax Cash Flow (MM \$Cdn.)	Owners Net Cash Flow (MM \$Cdn.)	Royalties Paid (MM \$Cdn.)
1988	1.000	0	0	0	0	0	0
1989	1.042	0	0	0	0	0	0
1990	1.086	0	0	28	0	-28	0
1991	1.131	0	0	105	0	-105	0
1992	1.179	0	0	207	0	-207	0
1993	1.228	0	0	463	0	-463	0
1994	1.280	0	0	352	0	-352	0
1995	1.334	0	0	426	0	-426	0
1996	1.390	7	500	548	-69	-617	3
1997	1.446	18	521	0	170	170	8
1998	1.509	25	543	0	330	330	24
1999	1.572	26	566	0	345	345	29
2000	1.638	28	655	0	345	345	47
2001	1.707	28	683	0	388	388	51
2002	1.779	28	712	0	426	426	73
2003	1.854	28	741	0	473	473	78
2004	1.931	28	773	0	507	507	105
2005	2.013	28	805	0	554	554	113
2006	2.097	28	839	0	605	605	122
2007	2.185	28	874	0	550	550	368
2008	2.277	28	911	0	599	599	403
2009	2.373	28	949	0	623	623	420
2010	2.472	28	989	0	647	647	437
2011	2.576	28	1030	0	673	673	456
2012	2.684	28	1074	0	611	611	412
2013	2.797	28	1119	0	861	861	589
2014	2.914	28	1166	0	838	838	736
2015	3.037	28	1215	0	872	872	767
2016	3.164	28	1266	0	907	907	799
2017	3.297	28	1319	0	944	944	833
2018	3.436	28	1374	0	982	982	868
2019	3.580	28	1432	0	1022	1022	904
2020	3.730	28	1492	0	1064	1064	942
2021	3.887	28	1555	0	1076	1076	982
2022	4.050	28	1620	0	1121	1121	1023
2023	4.221	28	1688	0	1168	1168	1066
2024	4.398	28	1753	0	1215	1215	1164
2025	4.583	28	1820	0	1275	1275	1213
2026	4.775	28	1891	0	1329	1329	1263
2027	4.976	28	1945	0	1384	1384	1317
2028	5.185	28	1991	0	1442	1442	1372
2029	5.402	28	2045	0	1503	1503	1429
2030	5.629	28	2077	0	1566	1566	1490

SOURCE: Canadian Energy Research Institute.



F.2 HIBERNIA



TABLE F.2a
HIBERNIA PROJECT ASSUMPTIONS^a

Year	Capital Expenditures (MM \$Cdn.)	Development Drilling (MM \$Cdn.)	Operating Costs (MM \$Cdn.)	Production Profile (MMb/yr.)
1989	152			
1990	480			
1991	831			
1992	1,308			
1993	1,206			
1994	1,168			
1995		243	113	8.0
1996		254	430	29.2
1997		195	621	40.2
1998		205	652	40.2
1999		215	685	40.2
2000		226	719	40.2
2001		238	755	40.2
2002		249	793	40.2
2003		262	832	40.2
2004		275	874	40.2
2005		289	918	40.2
2006		303	771	32.1
2007			644	25.6
2008			560	21.2
2009			427	15.3
2010			406	13.9
2011			336	11.0
2012			236	7.3
2013			162	4.8
2014			115	3.2
Totals	5,145	2,955	11,049	533.0

SOURCE: Canadian Energy Research Institute.

^aAll values expressed in current dollars.

TABLE F.2b

HIBERNIA PUBLIC SECTOR FINANCING ARRANGEMENTS
(millions of \$Cdn.)

Year	Government Grants ^a	Loan Guarantees ^b	Offshore Development Fund ^c	Cumulative Loan Guarantees	Interest On Loans (at 11%)
1989	38	61		61	7
1990	120	192		253	28
1991	211	337	25	590	65
1992	335	536	40	1,126	124
1993	312	499	30	1,625	179
1994	25	35		1,660	183
1995				1,660	183
1996				1,660	183
1997				1,660	183
1998				1,660	183
1999				1,660	183
2000				1,412	155
2001				1,093	120
2002				685	75
2003				175	19
2004				0	0
2005					
2006					
2007					
2008					
2009					
2010					
2011					
2012					
2013					
2014					

SOURCE: Canadian Energy Research Institute.

^aGovernment grants to the project capped at \$1.04 billion.

^bLoan Guarantees for the project capped at \$1.66 billion.

^cOffshore Development Fund established at a maximum of \$95 million.

TABLE F.2c
HIBERNIA PROJECT ECONOMICS

Discount Rate	Discounted Aggregated Value			Per Barrel Values				
	Capital (MM \$Cdn.)	Development Drilling (MM \$Cdn.)	Operating Costs (MM \$Cdn.)	Production Volume (MMb)	Capital Cost (\$Cdn.)	Development Drilling (\$Cdn.)	Operating Cost (\$Cdn.)	Total Cost (\$Cdn.)
0	4,212	1,639	5,445	533	7.90	3.07	10.22	21.20
5	4,616	1,228	3,676	360	12.83	3.41	10.22	26.46
7	4,789	1,107	3,194	313	15.32	3.54	10.22	29.08
10	5,060	959	2,628	257	19.68	3.73	10.22	33.62
12	5,249	877	2,329	228	23.03	3.85	10.22	37.10

SOURCE: Canadian Energy Research Institute.

TABLE F.2d
HIBERNIA PROJECT CASHFLOW
(millions of \$Cdn.)

Year	Owner Gross Cashflow	Royalty Revenue	Income Taxes Paid	Owner Net Cashflow	Government Cashflow	
					Net of Royalty and Taxes	Gross of Royalty and Taxes
1989	-60			-60	-38	-38
1990	-196			-196	-120	-120
1991	-335			-335	-211	-211
1992	-552			-552	-335	-335
1993	-585			-585	-312	-312
1994	-1341			-1341	-25	-25
1995	-183	2	0	-185	-31	-29
1996	409	16	0	393	35	51
1997	986	33	0	953	0	33
1998	1076	50	0	1026	0	50
1999	1003	72	0	931	0	72
2000	1108	332	12	764	0	344
2001	1231	369	375	487	0	744
2002	1367	410	416	541	0	826
2003	1973	592	601	780	0	1193
2004	2402	721	731	710	240	1692
2005	2660	798	810	786	266	1874
2006	2291	687	698	677	229	1614
2007	2289	687	697	676	229	1613
2008	2087	626	636	617	209	1471
2009	1595	478	486	471	159	1123
2010	1522	457	463	450	152	1072
2011	1268	380	386	375	127	893
2012	892	267	271	263	89	627
2013	619	186	188	183	62	436
2014	435	131	132	129	44	307

SOURCE: Canadian Energy Research Institute.

F.3 LLOYDMINSTER UPGRADER



TABLE F.3a
LLOYDMINSTER UPGRADE INPUT PRICES
(1988 \$Cdn./bbl)

Year	Light Oil Price (\$/bbl)	Condensate Price (\$/bbl)	Heavy Oil Blend Price (\$/bbl)	Bitumen Blend Price (\$/bbl)	Heavy Oil Price (\$/bbl)	Bitumen Price (\$/bbl)	Natural Gas Price (\$/Mcft)
1992	24.34	24.98	19.80	18.03	17.73	13.18	2.36
1993	24.81	25.45	19.95	18.18	17.83	13.17	2.47
1994	25.71	25.71	20.53	18.76	18.46	13.91	2.59
1995	26.64	26.64	21.16	19.39	19.04	14.39	2.71
1996	28.80	28.80	22.82	21.05	20.61	15.80	2.83
1997	30.13	30.13	23.83	22.06	21.56	16.65	2.96
1998	30.52	30.52	23.90	22.13	21.57	16.56	3.10
1999	32.01	32.01	25.06	23.29	22.67	17.56	3.24
2000	32.97	32.97	25.70	23.93	23.26	18.04	3.39
2001	34.10	34.74	26.51	24.74	23.89	18.37	3.65
2002	35.27	35.91	27.37	25.60	24.70	19.07	3.90
2003	36.49	38.64	28.27	26.50	25.27	19.06	4.16
2004	37.75	40.63	29.20	27.43	26.01	19.46	4.33
2005	39.04	41.92	30.18	28.41	26.93	20.28	4.53
2006	40.39	43.27	31.52	29.75	28.27	21.62	4.75
2007	41.76	46.76	32.90	31.13	29.27	21.94	4.96
2008	43.20	48.20	34.33	32.56	30.70	23.37	5.15

SOURCE: Canadian Energy Research Institute.

TABLE F.3b
LLOYDMINSTER UPGRADER
FEEDSTOCK AND OPERATING COSTS
(1988 \$Cdn/bbl)

Year	Operating Cost	Heavy Oil Component	Bitumen Component	Natural Gas Cost (\$/Mcf)	Price of Synthetic Crude	Net Operating Margin
1993	2.88	10.46	5.40	1.77	25.81	5.29
1994	2.88	10.52	5.40	1.85	26.71	6.06
1995	2.88	10.89	5.70	1.94	27.64	6.22
1996	2.88	11.23	5.90	2.03	29.80	7.75
1997	2.88	12.16	6.48	2.12	31.13	7.49
1998	2.88	12.72	6.83	2.22	31.52	6.87
1999	2.88	12.73	6.79	2.33	33.01	8.29
2000	2.88	13.38	7.20	2.43	33.97	8.08
2001	2.88	13.72	7.39	2.54	35.10	8.56
2002	2.88	14.10	7.53	2.74	36.27	9.03
2003	2.88	14.57	7.82	2.93	37.49	9.29
2004	2.88	14.91	7.81	3.12	38.75	10.03
2005	2.88	15.34	7.98	3.25	40.04	10.59
2006	2.88	15.89	8.31	3.40	41.39	10.91
2007	2.88	16.68	8.86	3.56	42.76	10.78
2008	2.88	17.27	9.00	3.72	44.20	11.34
2009	2.88	17.27	9.00	3.72	44.20	11.34
2010	2.88	17.27	9.00	3.72	44.20	11.34
2011	2.88	17.27	9.00	3.72	44.20	11.34
2012	2.88	17.27	9.00	3.72	44.20	11.34
2013	2.88	17.27	9.00	3.72	44.20	11.34
2014	2.88	17.27	9.00	3.72	44.20	11.34
2015	2.88	17.27	9.00	3.72	44.20	11.34
2016	2.88	17.27	9.00	3.72	44.20	11.34
2017	2.88	17.27	9.00	3.72	44.20	11.34
2018	2.88	17.27	9.00	3.72	44.20	11.34

SOURCE: Canadian Energy Research Institute.

TABLE F.3c
LLOYDMINSTER UPGRADE
OPERATING COSTS AND REVENUES
(constant 1988 dollars)

Year	Production Per Year (MMb)	Amortization of Capital (\$/bbl)	Operating Costs (\$/bbl)	Heavy Oil Component (\$/bbl)	Bitumen Component (\$/bbl)	Natural Gas Cost (\$/bbl)	Total Costs (\$/bbl)	Price of Synthetic (\$/bbl)	Profit (\$/bbl/yr.)	Net Operating Revenue (\$/yr.)
1993	16.00	10.35	2.02	12.62	6.52	2.14	35.10	31.13	-3.96	125.46
1994	16.00	10.85	2.12	13.29	6.83	2.34	36.95	33.77	-3.18	146.99
1995	16.00	11.37	2.22	14.43	7.56	2.57	39.74	36.62	-3.12	157.45
1996	16.00	11.91	2.32	15.60	8.19	2.82	42.52	41.38	-1.15	199.07
1997	16.00	12.48	2.44	17.69	9.43	3.09	46.89	45.30	-1.59	202.47
1998	16.00	13.08	2.55	19.40	10.41	3.39	50.67	48.07	-2.60	197.11
1999	16.00	13.71	2.67	20.34	10.85	3.72	53.22	52.75	-0.47	242.75
2000	16.00	14.37	2.80	22.41	12.05	4.07	57.72	56.89	-0.83	248.98
2001	16.00	15.06	2.94	24.08	12.98	4.46	61.64	61.61	-0.03	274.33
2002	16.00	15.78	3.08	25.93	13.85	5.04	65.90	66.72	0.82	301.14
2003	16.00	16.54	3.23	28.09	15.07	5.64	70.89	72.27	1.38	323.89
2004	16.00	17.33	3.38	30.12	16.78	6.30	76.36	78.29	2.93	363.18
2005	16.00	18.17	3.54	32.49	16.99	6.88	80.52	84.78	4.26	399.67
2006	16.00	19.04	3.71	35.26	18.45	7.54	86.68	91.84	5.17	430.09
2007	16.00	19.95	3.89	38.79	20.61	8.28	94.33	99.44	5.11	445.82
2008	16.00	20.91	4.08	42.09	21.92	9.07	101.00	107.72	6.71	489.03
2009	16.00	20.91	4.08	42.09	21.92	9.07	101.00	107.72	6.71	489.03
2010	16.00	20.91	4.08	42.09	21.92	9.07	101.00	107.72	6.71	489.03
2011	16.00	20.91	4.08	42.09	21.92	9.07	101.00	107.72	6.71	489.03
2012	16.00	20.91	4.08	42.09	21.92	9.07	101.00	107.72	6.71	489.03
2013	16.00	20.91	4.08	42.09	21.92	9.07	101.00	107.72	6.71	489.03
2014	16.00	20.91	4.08	42.09	21.92	9.07	101.00	107.72	6.71	489.03
2015	16.00	20.91	4.08	42.09	21.92	9.07	101.00	107.72	6.71	489.03
2016	16.00	20.91	4.08	42.09	21.92	9.07	101.00	107.72	6.71	489.03
2017	16.00	20.91	4.08	42.09	21.92	9.07	101.00	107.72	6.71	489.03
2018	16.00	20.91	4.08	42.09	21.92	9.07	101.00	107.72	6.71	489.03

SOURCE: Canadian Energy Research Institute.

TABLE F.3d
PAYOUT CALCULATIONS
LLOYDMINSTER UPGRADE
(millions of nominal \$Cdn.)

Year	Husky Pre-Tax Cash Flow	Husky After Tax Cash Flow	Class A Threshold Calculation	Class B Pre-Tax Cash Flow	Class B After Tax Cash Flow	Class B Threshold Calculation
1989			22.90			6.69
1990			98.81			21.71
1991			186.39			39.02
1992			247.56			51.21
1993	62.73	58.99	213.33	12.55	12.55	43.78
1994	73.50	59.11	175.55	14.70	13.82	34.33
1995	78.73	57.59	135.52	15.75	13.02	24.74
1996	99.54	65.95	83.12	19.91	14.32	12.90
1997	56.62	39.65	51.78	20.25	13.84	0.35
1998	98.56	61.02	-4.06	9.86	7.35	-6.96
1999	60.69	38.33	-42.80	12.14	8.21	-15.87
2000	62.24	38.15	-85.23	12.45	8.07	-42.36
2001	68.58	40.92	-134.67	13.72	8.55	-74.03
2002	75.29	44.09	-192.23	15.06	9.13	-111.55
2003	80.97	46.84	-258.30	16.19	9.64	-155.09
2004	90.80	52.03	-296.23	18.16	10.66	-206.92
2005	99.92	56.91	-339.18	19.98	11.62	
2006	107.52	60.99	-387.43	21.50	12.43	
2007	111.46	63.06	-441.04	22.29	12.84	
2008	122.26	69.03		24.45	14.03	
2009	122.26	68.95		24.45	14.01	
2010	122.26	68.89		24.45	13.99	
2011	122.26	68.84		24.45	13.98	
2012	122.26	68.81		24.45	13.97	
2013	122.26	68.78		24.45	13.96	
2014	122.26	68.76		24.45	13.95	
2015	122.26	68.75		24.45	13.95	
2016	122.26	68.74		24.45	13.95	
2017	122.26	68.73		24.45	13.94	

SOURCE: Canadian Energy Research Institute.

TABLE F.3e

LLOYDMINSTER UPGRADE
PARTICIPANT'S CASH FLOWS
(millions of \$Cdn.)

Year	Husky Cash Flow	Alberta Government Cash Flow	Saskatchewan Government Cash Flow	Canadian Government Cash Flow
1989	-25.1	-32.35	-23.43	-42.39
1990	-80.8	-103.99	-75.30	-136.26
1991	-85.3	-109.77	-79.49	-143.83
1992	-46.7	-60.08	-43.51	-78.73
1993	63.2	20.31	12.55	25.69
1994	63.7	23.80	14.70	30.10
1995	61.9	25.49	15.75	32.24
1996	70.7	32.23	19.91	40.76
1997	44.3	32.78	20.25	41.46
1998	63.5	31.88	22.18	41.31
1999	41.1	58.66	24.27	76.87
2000	40.8	60.17	43.57	78.84
2001	43.8	66.30	48.01	86.87
2002	47.1	72.78	52.70	95.36
2003	50.1	78.27	56.68	102.57
2004	55.6	87.77	63.56	115.01
2005	60.8	96.59	69.94	126.56
2006	65.1	103.94	75.27	136.19
2007	67.3	107.74	78.02	141.18
2008	73.7	118.18	85.58	154.86
2009	73.7	118.20	85.58	154.86
2010	73.7	118.20	85.58	154.86
2011	73.7	118.20	85.58	154.86
2012	73.7	118.20	85.58	154.86
2013	73.7	118.20	85.58	154.86
2014	73.7	118.20	85.58	154.86
2015	73.7	118.20	85.58	154.86
2016	73.7	118.20	85.58	154.86
2017	73.7	118.20	85.58	154.86
Internal Rate of Return	19.0%	13.8%	13.2%	13.7%

SOURCE: Canadian Energy Research Institute.

TABLE F.3f
LLOYDMINSTER UPGRADE
LIQUID HYDROCARBON PRICES - LOW CASE
MINIMUM BITUMEN PRICE
(1988 \$Cdn. per barrel)

Year	Light Oil Price (\$/bbl)	Condensate Price (\$/bbl)	Heavy Oil Blend Price (\$/bbl)	Bitumen Blend Price (\$/bbl)	Heavy Oil Price (\$/bbl)	Bitumen Price (\$/bbl)	Natural Gas Price (\$/Mcf)
1992	12.23	12.87	7.68	5.91	7.00	6.00	2.36
1993	13.49	14.13	8.63	6.86	7.00	6.00	2.47
1994	16.34	16.34	11.17	9.40	9.10	6.00	2.59
1995	17.93	17.93	12.45	10.68	10.33	6.00	2.71
1996	20.15	20.15	14.16	12.39	11.95	7.14	2.83
1997	21.94	21.94	15.64	13.87	13.37	8.46	2.96
1998	23.88	23.88	17.25	15.48	14.92	9.91	3.10
1999	25.81	25.81	18.87	17.10	16.49	11.37	3.24
2000	27.92	27.92	20.65	18.88	18.21	12.98	3.39
2001	29.03	29.67	21.45	19.68	18.84	13.31	3.65
2002	30.20	30.84	22.29	20.52	19.62	13.99	3.90
2003	31.40	33.55	23.18	21.41	20.18	13.97	4.16
2004	32.65	35.53	24.10	22.33	20.91	14.35	4.33
2005	33.85	36.73	24.99	23.22	21.74	15.09	4.53
2006	35.08	37.96	26.22	24.45	22.97	16.32	4.75
2007	36.36	41.36	27.50	25.73	23.87	16.54	4.96
2008	37.70	42.70	28.83	27.06	25.20	17.87	5.15

SOURCE: Canadian Energy Research Institute.

TABLE F.3g
LLOYDMINSTER UPGRADE
LOW PRICES - MINIMUM BITUMEN PRICE
(constant 1988 dollars)

Year	Production Per Year (MMb)	Amortization of Capital (\$/bbl)	Operating Costs (\$/bbl)	Heavy Oil Component (\$/bbl)	Bitumen Component (\$/bbl)	Natural Gas Cost (\$/bbl)	Total Costs (\$/bbl)	Price of Production (\$/bbl)	Profit (\$/bbl)
1993	16.00	10.35	2.02	4.98	2.97	2.14	23.91	17.48	-6.43
1994	16.00	10.85	2.12	5.22	3.11	2.34	25.16	21.92	-3.24
1995	16.00	11.37	2.22	7.12	3.26	2.57	28.13	25.08	-3.05
1996	16.00	11.91	2.32	8.46	3.42	2.82	30.61	29.37	-1.24
1997	16.00	12.48	2.44	10.26	4.26	3.09	34.28	33.38	-0.90
1998	16.00	13.08	2.55	12.03	5.29	3.39	38.18	37.94	-0.24
1999	16.00	13.71	2.67	14.07	6.49	3.72	42.59	42.85	0.26
2000	16.00	14.37	2.80	16.29	7.81	4.07	47.36	48.44	1.07
2001	16.00	15.06	2.94	18.85	9.34	4.46	52.78	52.71	-0.07
2002	16.00	15.78	3.08	20.44	10.04	5.04	56.60	57.39	0.80
2003	16.00	16.54	3.23	22.31	11.05	5.64	61.10	62.46	1.36
2004	16.00	17.33	3.38	24.05	11.57	6.30	65.08	67.98	2.91
2005	16.00	18.17	3.54	26.12	12.46	6.88	69.72	73.79	4.07
2006	16.00	19.04	3.71	28.46	13.73	7.54	75.16	80.06	4.90
2007	16.00	19.95	3.89	31.52	15.56	8.28	82.01	86.88	4.87
2008	16.00	20.91	4.08	34.32	21.92	9.07	93.24	94.31	1.08
2009	16.00	20.91	4.08	34.32	21.92	9.07	93.24	94.31	1.08
2010	16.00	20.91	4.08	34.32	21.92	9.07	93.24	94.31	1.08
2011	16.00	20.91	4.08	34.32	21.92	9.07	93.24	94.31	1.08
2012	16.00	20.91	4.08	34.32	21.92	9.07	93.24	94.31	1.08
2013	16.00	20.91	4.08	34.32	21.92	9.07	93.24	94.31	1.08
2014	16.00	20.91	4.08	34.32	21.92	9.07	93.24	94.31	1.08
2015	16.00	20.91	4.08	34.32	21.92	9.07	93.24	94.31	1.08
2016	16.00	20.91	4.08	34.32	21.92	9.07	93.24	94.31	1.08
2017	16.00	20.91	4.08	34.32	21.92	9.07	93.24	94.31	1.08
2018	16.00	20.91	4.08	34.32	21.92	9.07	93.24	94.31	1.08

SOURCE: Canadian Energy Research Institute.

TABLE F.3h
LLOYDMINSTER UPGRADE
LOW PRICES - MINIMUM BITUMEN PRICE CASH FLOWS
 (millions of \$Cdn.)

Year	Net Operating Revenue	Huaky Cash Flow	Alberta Government Cash Flow	Saskatchewan Government Cash Flow	Canadian Government Cash Flow
1989	0.0	-25.1	-32.35	-23.43	-42.39
1990	0.0	-50.8	-103.99	-75.30	-136.26
1991	0.0	-85.3	-109.77	-79.49	-143.83
1992	0.0	-46.7	-60.08	-43.51	-78.73
1993	86.01	47.2	13.92	8.60	17.61
1994	146.11	64.7	23.66	14.61	29.92
1995	158.60	63.2	25.68	15.86	32.48
1996	197.49	70.9	31.97	19.75	40.44
1997	213.49	46.5	34.56	21.35	43.71
1998	234.93	74.8	38.00	26.43	49.24
1999	254.33	43.1	61.46	44.51	80.54
2000	279.44	45.6	67.53	48.90	88.49
2001	273.76	43.8	66.16	47.91	86.69
2002	300.76	47.2	72.68	52.63	95.24
2003	323.68	50.1	78.22	56.64	102.50
2004	362.86	55.6	87.69	63.50	114.91
2005	396.62	60.4	95.85	69.41	125.60
2006	425.83	64.5	102.91	74.52	134.85
2007	441.99	66.8	106.81	77.35	139.96
2008	398.80	66.8	106.81	77.35	139.96
2009	398.80	66.8	106.81	77.35	139.96
2010	398.80	66.8	106.81	77.35	139.96
2011	398.80	66.8	106.81	77.35	139.96
2012	398.80	66.8	106.81	77.35	139.96
2013	398.80	66.8	106.81	77.35	139.96
2014	398.80	66.8	106.81	77.35	139.96
2015	398.80	66.8	106.81	77.35	139.96
2016	398.80	66.8	106.81	77.35	139.96
2017	398.80	66.8	106.81	77.35	139.96
Internal Rate of Return		18.6%	13.6%	13.3%	13.5%

SOURCE: Canadian Energy Research Institute.

TABLE F.3i
 LLOYDMINSTER UPGRADE
 CONSTANT DIFFERENTIAL CASE
 PRICES AND INDEX
 (constant 1988 dollars)

Year	Light Oil Price (\$/bbl)	Condensate Price (\$/bbl)	Heavy Oil Blend Price (\$/bbl)	Bitumen Blend Price (\$/bbl)	Heavy Oil Price (\$/bbl)	Bitumen Price (\$/bbl)	Natural Gas Price (\$/Mcft)	Price Index	Differential (\$U.S.)	Exchange Rate (\$U.S.)	U.S. Crude Price Chicago (\$U.S.)
1989				16.05				1.000	4.00	0.81	18.54
1990				17.11				1.048	4.00	0.81	19.40
1991				17.88				1.098	4.00	0.80	19.82
1992				18.96	18.83	14.58	2.36	1.151	4.00	0.80	20.69
1993	24.34	24.98	20.73	19.42	19.29	15.04	2.47	1.206	4.00	0.80	21.06
1994	24.81	25.45	21.20	20.89	20.98	17.11	2.59	1.264	4.00	0.78	21.78
1995	25.71	25.71	22.66	21.86	21.96	18.09	2.71	1.325	4.00	0.78	22.53
1996	26.64	26.64	23.63	23.29	23.25	19.16	2.83	1.388	4.00	0.78	23.65
1997	28.80	28.80	25.06	24.63	24.59	20.50	2.96	1.455	4.00	0.78	24.69
1998	30.13	30.13	26.40	25.01	24.97	20.88	3.10	1.525	4.00	0.78	24.99
1999	30.52	30.52	26.78	26.50	26.46	22.37	3.24	1.598	4.00	0.78	26.15
2000	32.01	32.01	28.27	27.46	27.42	23.33	3.39	1.675	4.00	0.78	26.90
2001	32.97	32.97	29.23	27.46	27.42	23.33	3.39	1.675	4.00	0.78	26.90
2002	34.10	34.10	30.36	28.59	28.43	24.14	3.65	1.755	4.00	0.78	27.78
2003	35.27	35.91	31.54	29.77	29.61	25.32	3.90	1.839	4.00	0.78	28.70
2004	36.49	36.64	32.76	30.98	30.56	25.78	4.16	1.928	4.00	0.78	29.65
2005	37.75	40.63	34.01	32.24	31.68	26.67	4.33	2.020	4.00	0.78	30.63
2006	39.04	41.92	35.31	33.54	32.98	27.97	4.53	2.117	4.00	0.78	31.64
2007	40.39	43.27	36.55	34.88	34.33	29.31	4.75	2.219	4.00	0.78	32.69
2008	41.76	46.76	38.02	36.25	35.32	29.63	4.96	2.325	4.00	0.78	33.76
2009	43.20	48.20	39.46	37.69	36.75	31.06	5.15	2.437	4.00	0.78	34.86

SOURCE: Canadian Energy Research Institute.

TABLE F.3j
LLOYDMINSTER UPGRADE
CONSTANT DIFFERENTIAL CASE
COSTS AND NET OPERATING REVENUE
(constant 1988 dollars)

Year	Production Per Year (MMb)	Amortization of Capital (\$/bbl)	Operating Costs (\$/bbl)	Heavy Oil Component (\$/bbl)	Bitumen Component (\$/bbl)	Natural Gas Cost (\$/bbl)	Total Costs (\$/bbl)	Sales Price (\$/bbl)	Gross Profit (\$/bbl/yr.)	Net Operating Revenue (\$/yr.)
1993	16.00	10.35	2.02	13.40	7.21	2.14	36.57	31.13	-5.44	101.86
1994	16.00	10.85	2.12	14.39	7.79	2.34	39.01	33.77	-5.25	113.98
1995	16.00	11.37	2.22	16.40	9.30	2.57	43.45	36.62	-6.83	98.11
1996	16.00	11.91	2.32	17.98	10.30	2.82	47.01	41.38	-5.64	127.23
1997	16.00	12.48	2.44	19.96	11.43	3.09	51.16	45.30	-5.86	134.02
1998	16.00	13.08	2.55	22.12	12.82	3.39	55.80	48.07	-7.73	115.03
1999	16.00	13.71	2.67	23.55	13.68	3.72	59.26	52.75	-6.50	146.18
2000	16.00	14.37	2.80	26.15	15.36	4.07	64.77	56.89	-7.87	136.28
2001	16.00	15.06	2.94	28.40	16.79	4.46	69.76	61.61	-8.15	144.38
2002	18.00	15.78	3.08	30.86	18.20	5.04	75.18	66.72	-8.46	152.68
2003	16.00	16.54	3.23	33.68	20.01	5.64	81.43	72.27	-9.15	155.38
2004	16.00	17.33	3.38	36.43	21.36	6.30	87.24	78.29	-8.95	173.11
2005	16.00	18.17	3.54	39.58	23.15	6.88	93.87	84.78	-9.10	185.97
2006	16.00	19.04	3.71	43.18	25.44	7.54	101.59	91.84	-9.75	191.47
2007	16.00	19.85	3.89	47.10	27.95	8.28	109.98	99.44	-10.54	196.45
2008	16.00	20.91	4.08	50.78	29.60	9.07	117.38	107.72	-9.66	227.06
2009	16.00	20.91	4.08	50.78	29.60	9.07	117.38	107.72	-9.66	227.06
2010	16.00	20.91	4.08	50.78	29.60	9.07	117.38	107.72	-9.66	227.06
2011	16.00	20.91	4.08	50.78	29.60	9.07	117.38	107.72	-9.66	227.06
2012	16.00	20.91	4.08	50.78	29.60	9.07	117.38	107.72	-9.66	227.06
2013	16.00	20.91	4.08	50.78	29.60	9.07	117.38	107.72	-9.66	227.06
2014	16.00	20.91	4.08	50.78	29.60	9.07	117.38	107.72	-9.66	227.06
2015	16.00	20.91	4.08	50.78	29.60	9.07	117.38	107.72	-9.66	227.06
2016	16.00	20.91	4.08	50.78	29.60	9.07	117.38	107.72	-9.66	227.06
2017	16.00	20.91	4.08	50.78	29.60	9.07	117.38	107.72	-9.66	227.06

SOURCE: Canadian Energy Research Institute.

TABLE F.3k
LLOYDMINSTER UPGRADE
CONSTANT DIFFERENTIAL CASE
(millions of nominal \$Cdn.)

Year	Husky Cash Flow	Alberta Government Cash Flow	Saskatchewan Government Cash Flow	Canadian Government Cash Flow
1989	-25.1	-32.35	-23.43	-42.39
1990	-80.8	-103.99	-75.30	-136.26
1991	-85.3	-109.77	-79.49	-143.83
1992	-46.7	-60.08	-43.51	-78.73
1993	54.3	16.49	10.19	20.86
1994	54.0	18.45	11.40	23.34
1995	44.5	15.88	9.81	20.09
1996	49.5	20.60	12.72	26.05
1997	49.1	21.70	13.40	27.44
1998	39.8	18.62	12.94	23.55
1999	47.2	23.67	14.62	29.93
2000	43.2	21.98	15.33	28.56
2001	24.3	34.89	25.27	45.72
2002	24.9	36.90	26.72	48.35
2003	24.8	37.55	27.19	49.20
2004	27.1	41.83	30.29	54.82
2005	28.7	44.94	32.54	58.89
2006	29.4	46.27	33.51	60.63
2007	29.8	47.23	34.20	61.89
2008	34.4	54.87	39.74	71.90
2009	34.4	54.87	39.74	71.90
2010	34.4	54.87	39.74	71.90
2011	34.4	54.87	39.74	71.90
2012	34.4	54.87	39.74	71.90
2013	34.4	54.87	39.74	71.90
2014	34.4	54.87	39.74	71.90
2015	34.4	54.87	39.74	71.90
2016	34.4	54.87	39.74	71.90
2017	34.4	54.87	39.74	71.90
Internal Rate of Return	14.3%	8.0%	7.0%	7.9%

SOURCE: Canadian Energy Research Institute.



APPENDIX G**LIGHT CRUDE OIL BALANCES AND
REGIONAL DEMAND/SUPPLY ANALYSIS**

- G.1 *Low Price Case - Prudent Industrial Behaviour***
- G.2 *Base Case - Prudent Industrial Behaviour***
- G.3 *High Price Case - Prudent Industrial Behaviour***
- G.4 *Base Case - Perfect Foresight***
- G.5 *Base Case - All Megaprojects***
- G.6 *High Price Case - All Megaprojects***



G.1 LOW PRICE CASE
PRUDENT INDUSTRIAL BEHAVIOUR



TABLE G.1a
CANADIAN LIGHT OIL BALANCE
ALL REGIONS
(MMb/yr.)

Year	Conventional Light Oil Production	Synthetic Oil Production	Light Oil Demand	Net Light Oil Imports
1988	352.2	77.8	483.0	53.0
1989	322.8	91.6	513.0	98.6
1990	295.0	94.6	553.0	158.9
1991	271.0	94.6	602.0	228.0
1992	249.4	96.6	652.0	296.4
1993	232.9	96.6	681.0	340.6
1994	213.6	96.6	696.0	369.5
1995	198.5	96.6	703.0	385.2
1996	187.6	96.6	704.0	395.6
1997	176.8	96.6	703.0	404.3
1998	168.0	96.6	698.0	414.5
1999	160.2	96.6	690.0	420.0
2000	152.9	93.6	684.0	426.9
2001	145.5	89.6	677.0	433.6
2002	138.9	80.6	670.0	443.4
2003	133.0	71.6	667.0	456.8
2004	159.3	71.6	662.0	431.1
2005	167.5	77.8	657.0	411.7
2006	164.9	71.6	651.0	414.5
2007	174.1	77.3	645.0	393.6
2008	175.3	94.3	639.0	369.4

SOURCE: Canadian Energy Research Institute.

TABLE G.1b
CANADIAN LIGHT OIL BALANCE
WESTERN CANADA REGION
(MMb/yr.)

Year	Conventional Light Oil Supply	Synthetic Oil Production	Beaufort Production	Light Oil Demand	Shipments To Canada	Light Oil Exports
1988	352.2	77.8	0.0	166.0	237.0	27.0
1989	322.8	91.6	0.0	177.0	237.4	0.0
1990	295.0	94.6	0.0	190.0	204.1	0.0
1991	271.0	94.6	0.0	206.0	168.0	0.0
1992	249.4	96.6	0.0	223.0	132.6	0.0
1993	232.9	96.6	0.0	233.0	107.4	0.0
1994	213.6	96.6	0.0	238.0	88.5	0.0
1995	198.5	96.6	0.0	241.0	77.4	0.0
1996	187.6	96.6	0.0	240.0	68.4	0.0
1997	176.8	96.6	0.0	240.0	58.7	0.0
1998	168.0	96.6	0.0	238.0	45.5	0.0
1999	160.2	96.6	0.0	235.0	35.0	0.0
2000	152.9	93.6	0.0	234.0	23.1	0.0
2001	145.5	89.6	0.0	234.0	9.8	0.0
2002	138.9	80.6	0.0	232.0	0.0	0.0
2003	133.0	71.6	0.0	231.0	0.0	0.0
2004	127.3	71.6	32.0	230.0	0.9	0.0
2005	122.4	77.8	45.1	228.0	17.3	0.0
2006	118.6	71.6	46.3	226.0	10.5	0.0
2007	114.5	77.3	59.6	223.0	28.4	0.0
2008	110.3	94.3	71.0	221.0	54.6	0.0

SOURCE: Canadian Energy Research Institute.

TABLE G.1c
CANADIAN LIGHT OIL BALANCE
CENTRAL CANADA REGION
(MMb/yr.)

Year	Light Oil Demand	Western Canadian Shipments	Light Oil Imports
1988	237.0	237.0	0.0
1989	251.0	237.4	13.6
1990	270.0	204.1	65.9
1991	294.0	168.0	126.0
1992	318.0	132.6	185.4
1993	333.0	107.4	225.6
1994	342.0	88.5	253.5
1995	347.0	77.4	269.6
1996	350.0	68.4	281.6
1997	351.0	58.7	292.3
1998	350.0	45.5	304.5
1999	348.0	35.0	313.0
2000	345.0	23.1	321.9
2001	340.0	9.8	330.2
2002	337.0	0.0	337.0
2003	335.0	0.0	335.0
2004	332.0	0.9	331.1
2005	329.0	17.3	311.7
2006	326.0	10.5	315.5
2007	324.0	28.4	295.6
2008	321.0	54.6	266.4

SOURCE: Canadian Energy Research Institute.

TABLE G.1d
CANADIAN LIGHT OIL BALANCE
EASTERN CANADA REGION
(MMb/yr.)

Year	Light Oil Demand	Light Oil Imports
1988	80.0	80.0
1989	85.0	85.0
1990	93.0	93.0
1991	102.0	102.0
1992	111.0	111.0
1993	115.0	115.0
1994	116.0	116.0
1995	115.0	115.0
1996	114.0	114.0
1997	112.0	112.0
1998	110.0	110.0
1999	107.0	107.0
2000	105.0	105.0
2001	103.0	103.0
2002	101.0	101.0
2003	101.0	101.0
2004	100.0	100.0
2005	100.0	100.0
2006	99.0	99.0
2007	98.0	98.0
2008	97.0	97.0

SOURCE: Canadian Energy Research Institute.

G.2 BASE CASE
PRUDENT INDUSTRIAL BEHAVIOUR



TABLE G.2a
CANADIAN LIGHT OIL BALANCE
ALL REGIONS
(MMb/yr.)

Year	Conventional Light Oil Production	Synthetic Oil Production	Light Oil Demand	Net Light Oil Imports
1988	353.4	77.8	483.0	51.8
1989	327.3	91.6	500.0	81.1
1990	304.4	94.6	522.0	123.0
1991	286.0	94.6	547.0	166.4
1992	269.9	96.6	572.0	205.5
1993	258.2	96.6	589.0	234.4
1994	242.8	96.6	600.0	260.6
1995	230.5	96.6	606.0	278.9
1996	221.7	96.6	608.0	289.7
1997	212.6	96.6	610.0	300.8
1998	205.0	98.8	612.0	308.2
1999	197.0	99.4	612.0	315.6
2000	190.8	97.7	611.0	322.5
2001	183.3	93.7	612.0	335.0
2002	176.6	87.8	611.0	346.6
2003	170.5	94.8	612.0	346.7
2004	209.8	110.8	610.0	289.4
2005	223.2	116.9	608.0	267.9
2006	234.3	122.5	606.0	249.2
2007	205.8	139.6	604.0	158.6
2008	336.2	161.5	599.0	101.3

SOURCE: Canadian Energy Research Institute.

TABLE G.2b
CANADIAN LIGHT OIL BALANCE
WESTERN CANADA REGION
(MMb/yr.)

Year	Conventional Light Oil Supply	Synthetic Oil Production	Beaufort Production	Light Oil Demand	Shipments To Canada	Light Oil Exports
1988	353.4	77.8	0.0	166.0	237.0	28.2
1989	327.3	91.6	0.0	172.0	245.0	1.9
1990	304.4	94.6	0.0	179.0	220.0	0.0
1991	286.0	94.6	0.0	186.0	194.6	0.0
1992	269.9	96.6	0.0	194.0	172.5	0.0
1993	258.2	96.6	0.0	200.0	154.8	0.0
1994	242.8	96.6	0.0	204.0	135.4	0.0
1995	230.5	96.6	0.0	206.0	121.1	0.0
1996	221.7	96.6	0.0	205.0	113.3	0.0
1997	212.6	96.6	0.0	206.0	103.2	0.0
1998	205.0	98.8	0.0	207.0	95.8	0.0
1999	197.0	99.4	0.0	207.0	89.4	0.0
2000	190.8	97.1	0.0	208.0	79.9	0.0
2001	183.3	93.7	0.0	209.0	68.0	0.0
2002	176.6	87.8	0.0	209.0	55.4	0.0
2003	170.5	94.8	0.0	210.0	55.3	0.0
2004	164.4	110.8	45.4	210.0	110.6	0.0
2005	159.4	116.9	63.8	209.0	131.1	0.0
2006	155.2	122.5	65.5	208.0	135.2	0.0
2007	150.8	139.6	105.7	207.0	189.1	0.0
2008	146.4	161.5	122.0	205.0	224.9	0.0

SOURCE: Canadian Energy Research Institute.

TABLE G.2c
CANADIAN LIGHT OIL BALANCE
CENTRAL CANADA REGION
(MMb/yr.)

Year	Light Oil Demand	Western Canadian Shipments	Light Oil Imports
1988	237.0	237.0	0.0
1989	245.0	245.0	0.0
1990	256.0	220.0	36.0
1991	269.0	194.6	74.4
1992	282.0	172.5	109.5
1993	291.0	154.8	136.2
1994	297.0	135.4	161.6
1995	301.0	121.1	179.9
1996	304.0	113.3	190.7
1997	306.0	103.2	202.8
1998	307.0	95.8	211.2
1999	308.0	89.4	218.6
2000	306.0	79.9	226.1
2001	306.0	68.0	238.0
2002	305.0	55.4	249.6
2003	305.0	55.3	249.5
2004	303.0	110.6	192.4
2005	302.0	131.1	170.9
2006	301.0	135.2	166.0
2007	301.0	189.1	111.9
2008	298.0	224.9	73.1

SOURCE: Canadian Energy Research Institute.

TABLE G.2d
CANADIAN LIGHT OIL BALANCE
EASTERN CANADA REGION
(MMb/yr.)

Year	Light Oil Demand	Hibernia Production	Light Oil Imports
1988	80.0	0.0	80.0
1989	83.0	0.0	83.0
1990	87.0	0.0	87.0
1991	92.0	0.0	92.0
1992	96.0	0.0	96.0
1993	98.0	0.0	98.0
1994	99.0	0.0	99.0
1995	99.0	0.0	99.0
1996	99.0	0.0	99.0
1997	98.0	0.0	98.0
1998	98.0	0.0	98.0
1999	97.0	0.0	97.0
2000	97.0	0.0	97.0
2001	97.0	0.0	97.0
2002	97.0	0.0	97.0
2003	97.0	0.0	97.0
2004	97.0	0.0	97.0
2005	97.0	0.0	97.0
2006	97.0	13.6	83.4
2007	96.0	49.3	46.7
2008	96.0	67.8	28.2

SOURCE: Canadian Energy Research Institute.

G.3 HIGH PRICE CASE
PRUDENT INDUSTRIAL BEHAVIOUR



TABLE G.3a
CANADIAN LIGHT OIL BALANCE
ALL REGIONS
(MMb/yr.)

Year	Conventional Light Oil Production	Synthetic Oil Production	Light Oil Demand	Net Light Oil Imports
1988	355.5	77.8	475.0	41.7
1989	333.8	91.6	492.0	66.6
1990	315.6	94.6	511.0	100.8
1991	302.4	94.6	535.0	137.9
1992	291.4	96.6	557.0	169.0
1993	284.4	96.6	572.0	191.0
1994	273.4	101.7	581.0	205.9
1995	265.3	102.5	586.0	218.2
1996	260.2	118.5	586.0	207.3
1997	254.4	130.9	587.0	201.7
1998	249.8	146.9	586.0	189.3
1999	245.3	154.1	585.0	185.6
2000	240.6	155.6	583.0	186.8
2001	235.1	151.6	582.0	195.3
2002	230.0	144.4	581.0	206.6
2003	225.4	144.8	580.0	209.8
2004	266.1	160.8	579.0	152.1
2005	280.5	164.9	576.0	130.6
2006	382.4	170.6	574.0	21.0
2007	451.1	187.6	569.0	-69.7
2008	469.4	209.5	564.0	-114.8

SOURCE: Canadian Energy Research Institute.

TABLE G.3b
CANADIAN LIGHT OIL BALANCE
WESTERN CANADA REGION
(MMb/yr.)

Year	Conventional Light Oil Supply	Synthetic Oil Production	Beaufort Production	Light Oil Demand	Shipments To Canada	Light Oil Exports
1988	355.5	77.8	0.0	163.0	234.0	36.3
1989	333.8	91.6	0.0	169.0	241.0	15.4
1990	315.6	94.6	0.0	175.0	235.2	0.0
1991	302.4	94.6	0.0	182.0	215.1	0.0
1992	291.4	96.6	0.0	189.0	199.0	0.0
1993	284.4	96.6	0.0	194.0	187.0	0.0
1994	273.4	101.7	0.0	197.0	178.4	0.0
1995	265.3	102.5	0.0	199.0	168.8	0.0
1996	260.2	118.4	0.0	198.0	180.6	0.0
1997	254.4	130.9	0.0	198.0	187.3	0.0
1998	249.8	146.9	0.0	198.0	198.7	0.0
1999	245.3	154.1	0.0	198.0	201.4	0.0
2000	240.6	155.6	0.0	198.0	198.2	0.0
2001	235.1	151.6	0.0	199.0	187.7	0.0
2002	230.0	144.4	0.0	199.0	175.4	0.0
2003	225.3	144.8	0.0	199.0	171.1	0.0
2004	220.6	160.8	45.4	199.0	227.8	0.0
2005	216.7	164.9	63.8	198.0	247.4	0.0
2006	213.7	170.6	155.1	197.0	286.0	56.4
2007	210.2	187.6	191.6	195.0	284.0	110.4
2008	206.7	209.5	194.9	193.0	282.0	136.1

SOURCE: Canadian Energy Research Institute.

TABLE G.3c
CANADIAN LIGHT OIL BALANCE
CENTRAL CANADA REGION
(MMb/yr.)

Year	Light Oil Demand	Western Canadian Shipments	Light Oil Imports
1988	234.0	234.0	0.0
1989	241.0	241.0	0.0
1990	251.0	235.2	15.8
1991	263.0	215.1	47.9
1992	275.0	199.0	76.0
1993	283.0	187.0	96.0
1994	288.0	178.4	109.6
1995	292.0	168.8	123.2
1996	293.0	180.6	112.4
1997	295.0	187.3	107.7
1998	295.0	198.7	96.3
1999	295.0	201.4	93.6
2000	293.0	198.2	94.8
2001	292.0	187.7	104.3
2002	291.0	175.4	115.6
2003	290.0	171.1	118.9
2004	289.0	227.8	61.2
2005	287.0	247.4	39.6
2006	286.0	286.0	0.0
2007	284.0	284.0	0.0
2008	282.0	282.0	0.0

SOURCE: Canadian Energy Research Institute.

TABLE G.3d
CANADIAN LIGHT OIL BALANCE
EASTERN CANADA REGION
(MMb/yr.)

Year	Light Oil Demand	Hibernia Production	Light Oil Imports
1988	78.0	0.0	78.0
1989	82.0	0.0	82.0
1990	85.0	0.0	85.0
1991	90.0	0.0	90.0
1992	93.0	0.0	93.0
1993	95.0	0.0	95.0
1994	96.0	0.0	96.0
1995	95.0	0.0	95.0
1996	95.0	0.0	95.0
1997	94.0	0.0	94.0
1998	93.0	0.0	93.0
1999	92.0	0.0	92.0
2000	92.0	0.0	92.0
2001	91.0	0.0	91.0
2002	91.0	0.0	91.0
2003	91.0	0.0	91.0
2004	91.0	0.0	91.0
2005	91.0	0.0	91.0
2006	91.0	13.6	77.4
2007	90.0	49.3	40.7
2008	89.0	67.8	21.2

SOURCE: Canadian Energy Research Institute.

**G.4 BASE CASE
PERFECT FORESIGHT**



TABLE G.4a
CANADIAN LIGHT OIL BALANCE
ALL REGIONS
(MMb/yr.)

Year	Conventional Light Oil Production	Synthetic Oil Production	Light Oil Demand	Net Light Oil Imports
1988	353.4	77.8	483.0	51.8
1989	327.3	91.6	500.0	81.1
1990	304.4	94.6	522.0	123.0
1991	286.0	94.6	547.0	166.4
1992	269.9	96.6	572.0	205.5
1993	258.2	96.6	589.0	234.2
1994	242.8	96.6	600.0	259.9
1995	230.5	96.6	606.0	271.7
1996	221.7	96.6	608.0	289.7
1997	212.6	102.3	610.0	295.1
1998	205.0	129.7	612.0	277.3
1999	211.4	155.8	612.0	244.8
2000	272.1	193.1	611.0	145.8
2001	296.3	231.1	612.0	84.6
2002	304.0	251.7	611.0	55.3
2003	303.3	271.1	612.0	37.6
2004	297.2	305.4	610.0	7.4
2005	292.2	342.2	608.0	-26.4
2006	288.1	370.6	606.0	-52.7
2007	320.6	398.1	604.0	-114.7
2008	321.4	419.2	599.0	-141.6

SOURCE: Canadian Energy Research Institute.

TABLE G.4b
CANADIAN LIGHT OIL BALANCE
WESTERN CANADA REGION
(MMb/yr.)

Year	Conventional Light Oil Supply	Synthetic Oil Production	Beaufort Production	Light Oil Demand	Shipments To Canada	Light Oil Exports
1988	353.4	77.8	0.0	166.0	237.0	28.2
1989	327.3	91.6	0.0	172.0	245.0	1.9
1990	304.4	94.6	0.0	179.0	220.0	0.0
1991	286.0	94.6	0.0	186.0	194.6	0.0
1992	269.9	96.6	0.0	194.0	172.5	0.0
1993	258.2	96.6	0.0	200.0	154.8	0.0
1994	242.8	96.6	0.0	204.0	136.1	0.0
1995	230.5	96.6	0.0	206.0	128.3	0.0
1996	221.7	96.6	0.0	205.0	112.3	0.0
1997	212.6	102.3	0.0	206.0	108.9	0.0
1998	205.0	129.7	0.0	207.0	127.7	0.0
1999	197.8	155.8	0.0	207.0	146.6	0.0
2000	190.8	193.1	32.0	208.0	207.9	0.0
2001	183.4	231.1	45.1	209.0	250.6	0.0
2002	176.6	251.7	59.6	209.0	278.9	0.0
2003	170.5	271.1	65.0	210.0	296.6	0.0
2004	164.4	305.4	65.5	210.0	303.0	22.3
2005	159.4	342.2	65.5	209.0	302.0	56.1
2006	155.3	370.6	65.5	208.0	301.0	80.3
2007	150.7	398.1	102.1	207.0	301.0	142.9
2008	146.3	419.2	107.3	205.0	298.0	169.8

SOURCE: Canadian Energy Research Institute.

TABLE G.4c
CANADIAN LIGHT OIL BALANCE
CENTRAL CANADA REGION
(MMb/yr.)

Year	Light Oil Demand	Western Canadian Shipments	Light Oil Imports
1988	237.0	237.0	0.0
1989	245.0	245.0	0.0
1990	256.0	220.0	36.0
1991	269.0	194.6	74.4
1992	282.0	172.5	109.5
1993	291.0	154.8	136.2
1994	297.0	136.1	160.9
1995	301.0	128.3	172.7
1996	304.0	112.3	191.7
1997	306.0	108.9	197.1
1998	307.0	127.7	179.3
1999	308.0	146.6	161.4
2000	306.0	207.9	98.1
2001	306.0	250.6	55.4
2002	305.0	278.9	26.1
2003	305.0	296.6	8.4
2004	303.0	303.0	0.0
2005	302.0	302.0	0.0
2006	301.0	301.0	0.0
2007	301.0	301.0	0.0
2008	298.0	298.0	0.0

SOURCE: Canadian Energy Research Institute.

TABLE G.4d
CANADIAN LIGHT OIL BALANCE
EASTERN CANADA REGION
(MMb/yr.)

Year	Light Oil Demand	Hibernia Production	Light Oil Imports
1988	80.0	0.0	80.0
1989	83.0	0.0	83.0
1990	87.0	0.0	87.0
1991	92.0	0.0	92.0
1992	96.0	0.0	96.0
1993	98.0	0.0	98.0
1994	99.0	0.0	99.0
1995	99.0	0.0	99.0
1996	99.0	0.0	99.0
1997	98.0	0.0	98.0
1998	98.0	0.0	98.0
1999	97.0	13.6	83.4
2000	97.0	49.3	47.7
2001	97.0	67.8	29.2
2002	97.0	67.8	29.2
2003	97.0	67.8	29.2
2004	97.0	67.8	29.2
2005	97.0	67.8	29.2
2006	97.0	67.8	29.2
2007	96.0	67.8	28.2
2008	96.0	67.8	28.2

SOURCE: Canadian Energy Research Institute.

**G.5 BASE CASE
ALL MEGAPROJECTS**



TABLE G.5a
CANADIAN LIGHT OIL BALANCE
ALL REGIONS
(MMb/yr.)

Year	Conventional Light Oil Production	Synthetic Oil Production	Light Oil Demand	Net Light Oil Imports
1988	353.4	77.8	483.0	51.8
1989	327.3	91.6	500.0	81.1
1990	304.4	94.6	522.0	123.0
1991	286.0	94.6	547.0	166.4
1992	269.9	96.6	572.0	205.5
1993	258.2	113.4	589.0	217.4
1994	242.8	113.4	600.0	243.8
1995	243.1	116.2	606.0	246.7
1996	267.4	124.6	608.0	216.0
1997	275.4	132.6	610.0	202.0
1998	267.7	136.2	612.0	208.1
1999	260.5	141.2	612.0	210.3
2000	253.5	155.7	611.0	201.8
2001	246.1	164.5	612.0	201.4
2002	239.3	157.2	611.0	214.5
2003	233.2	148.2	612.0	230.6
2004	272.6	154.2	610.0	365.8
2005	285.9	162.6	608.0	159.5
2006	272.1	168.3	606.0	165.6
2007	300.1	185.3	604.0	118.6
2008	306.5	207.2	599.0	85.3

SOURCE: Canadian Energy Research Institute.

TABLE G.5b
CANADIAN LIGHT OIL BALANCE
WESTERN CANADA REGION
(MMb/yr.)

Year	Conventional Light Oil Supply	Synthetic Oil Production	Beaufort Production	Light Oil Demand	Shipments To Canada	Light Oil Exports
1988	353.4	77.8	0.0	166.0	237.0	28.2
1989	327.3	91.6	0.0	172.0	245.0	1.9
1990	304.4	94.6	0.0	179.0	220.0	0.0
1991	286.0	94.6	0.0	186.0	194.6	0.0
1992	269.9	96.6	0.0	194.0	172.5	0.0
1993	258.2	113.4	0.0	200.0	171.6	0.0
1994	242.8	113.4	0.0	204.0	152.2	0.0
1995	230.5	116.2	0.0	206.0	140.7	0.0
1996	221.7	124.6	0.0	205.0	141.3	0.0
1997	212.6	132.6	0.0	206.0	139.2	0.0
1998	204.9	136.2	0.0	207.0	134.1	0.0
1999	197.7	141.2	0.0	207.0	131.9	0.0
2000	190.7	155.7	0.0	208.0	138.4	0.0
2001	183.3	164.5	0.0	209.0	138.8	0.0
2002	176.5	157.2	0.0	209.0	124.7	0.0
2003	170.4	148.2	0.0	210.0	108.6	0.0
2004	164.4	154.2	45.4	210.0	154.0	0.0
2005	159.3	162.6	63.8	209.0	176.7	0.0
2006	155.3	168.3	65.5	208.0	181.1	0.0
2007	150.8	185.3	105.7	207.0	234.8	0.0
2008	146.4	207.2	122.0	205.0	270.6	0.0

SOURCE: Canadian Energy Research Institute.

TABLE G.5c
CANADIAN LIGHT OIL BALANCE
CENTRAL CANADA REGION
(MMb/yr.)

Year	Light Oil Demand	Western Canadian Shipments	Light Oil Imports
1988	237.0	237.0	0.0
1989	245.0	245.0	0.0
1990	256.0	220.0	36.0
1991	269.0	194.6	74.4
1992	282.0	172.5	109.5
1993	291.0	171.6	119.4
1994	297.0	152.2	144.8
1995	301.0	140.7	160.3
1996	304.0	141.3	162.7
1997	306.0	139.2	166.8
1998	307.0	134.1	172.9
1999	308.0	131.9	176.1
2000	306.0	138.4	167.6
2001	306.0	138.8	167.2
2002	305.0	124.7	180.3
2003	305.0	108.6	196.4
2004	303.0	154.0	149.0
2005	302.0	176.7	125.3
2006	301.0	181.1	119.9
2007	301.0	234.8	66.2
2008	298.0	270.6	27.2

SOURCE: Canadian Energy Research Institute.

TABLE G.5d
CANADIAN LIGHT OIL BALANCE
EASTERN CANADA REGION
(MMb/yr.)

Year	Light Oil Demand	Hibernia Production	Light Oil Imports
1988	80.0	0.0	80.0
1989	83.0	0.0	83.0
1990	87.0	0.0	87.0
1991	92.0	0.0	92.0
1992	96.0	0.0	96.0
1993	98.0	0.0	98.0
1994	99.0	0.0	99.0
1995	99.0	12.6	86.4
1996	99.0	45.7	53.3
1997	98.0	62.8	35.2
1998	98.0	62.8	35.2
1999	97.0	62.8	34.2
2000	97.0	62.8	34.2
2001	97.0	62.8	34.2
2002	97.0	62.8	34.2
2003	97.0	62.8	34.2
2004	97.0	62.8	34.2
2005	97.0	62.8	34.2
2006	97.0	51.3	45.7
2007	96.0	43.6	52.4
2008	96.0	38.1	57.9

SOURCE: Canadian Energy Research Institute.

G.6 HIGH PRICE CASE
ALL MEGAPROJECTS



TABLE G.6a
CANADIAN LIGHT OIL BALANCE
ALL REGIONS
(MMb/yr.)

Year	Conventional Light Oil Production	Synthetic Oil Production	Light Oil Demand	Net Light Oil Imports
1988	355.5	77.8	475.0	41.7
1989	333.8	91.6	492.0	66.6
1990	315.6	94.6	511.0	100.8
1991	302.4	94.6	535.0	138.0
1992	291.4	96.6	557.0	168.7
1993	284.4	113.4	572.0	174.2
1994	273.4	114.1	581.0	193.4
1995	277.8	132.9	586.0	175.3
1996	305.9	153.1	586.0	127.0
1997	317.2	162.1	587.0	107.7
1998	312.6	173.8	586.0	99.6
1999	308.1	179.4	585.0	97.5
2000	303.4	190.1	583.0	89.5
2001	297.9	203.3	582.0	80.8
2002	292.8	203.3	581.0	84.9
2003	288.1	193.5	580.0	98.4
2004	328.9	193.5	579.0	56.6
2005	343.4	193.5	576.0	39.1
2006	420.1	199.2	574.0	-45.3
2007	445.3	215.6	569.0	-91.9
2008	439.6	238.1	564.0	-113.7

SOURCE: Canadian Energy Research Institute.

TABLE G.6b
CANADIAN LIGHT OIL BALANCE
WESTERN CANADA REGION
(MMb/yr.)

Year	Conventional Light Oil Supply	Synthetic Oil Production	Beaufort Production	Light Oil Demand	Shipments To Canada	Light Oil Exports
1988	355.5	77.8	0.0	163.0	234.0	36.3
1989	333.8	91.6	0.0	169.0	241.0	15.4
1990	315.6	94.6	0.0	175.0	235.2	0.0
1991	302.4	94.6	0.0	182.0	215.1	0.0
1992	291.4	96.6	0.0	189.0	199.0	0.0
1993	284.4	113.4	0.0	194.0	203.8	0.0
1994	273.4	114.1	0.0	197.0	190.5	0.0
1995	265.2	132.9	0.0	199.0	199.1	0.0
1996	260.2	153.1	0.0	198.0	215.3	0.0
1997	254.4	162.1	0.0	198.0	218.5	0.0
1998	249.8	173.8	0.0	198.0	225.6	0.0
1999	245.3	179.4	0.0	198.0	226.7	0.0
2000	240.6	190.1	0.0	198.0	232.7	0.0
2001	235.1	203.3	0.0	199.0	239.4	0.0
2002	230.0	203.3	0.0	199.0	234.3	0.0
2003	225.3	193.5	0.0	199.0	219.8	0.0
2004	220.7	193.5	45.4	199.0	260.6	0.0
2005	216.8	193.5	63.8	198.0	276.1	0.0
2006	213.7	199.2	155.1	197.0	286.0	85.0
2007	210.2	215.6	191.6	195.0	284.0	138.4
2008	206.6	238.1	194.9	193.0	282.0	164.6

SOURCE: Canadian Energy Research Institute.

TABLE G.6c
CANADIAN LIGHT OIL BALANCE
CENTRAL CANADA REGION
(MMb/yr.)

Year	Light Oil Demand	Western Canadian Shipments	Light Oil Imports
1988	234.0	234.0	0.0
1989	241.0	241.0	0.0
1990	251.0	235.2	15.8
1991	263.0	215.1	47.9
1992	275.0	199.0	76.0
1993	283.0	203.8	79.2
1994	288.0	190.5	97.5
1995	292.0	199.1	92.9
1996	293.0	215.3	77.7
1997	295.0	218.5	76.5
1998	295.0	225.6	69.4
1999	295.0	226.7	68.3
2000	293.0	232.7	60.3
2001	292.0	239.4	52.6
2002	291.0	234.3	56.7
2003	290.0	219.8	70.2
2004	289.0	260.6	28.4
2005	287.0	276.1	10.9
2006	286.0	286.0	0.0
2007	284.0	284.0	0.0
2008	282.0	282.0	0.0

SOURCE: Canadian Energy Research Institute.

TABLE G.6d
CANADIAN LIGHT OIL BALANCE
EASTERN CANADA REGION
(MMb/yr.)

Year	Light Oil Demand	Hibernia Production	Light Oil Imports
1988	78.0	0.0	78.0
1989	82.0	0.0	82.0
1990	85.0	0.0	85.0
1991	90.0	0.0	90.0
1992	93.0	0.0	93.0
1993	95.0	0.0	95.0
1994	96.0	0.0	96.0
1995	95.0	12.6	82.4
1996	95.0	45.7	49.3
1997	94.0	62.8	31.2
1998	93.0	62.8	30.2
1999	92.0	62.8	29.2
2000	92.0	62.8	29.2
2001	91.0	62.8	28.2
2002	91.0	62.8	28.2
2003	91.0	62.8	28.2
2004	91.0	62.8	28.2
2005	91.0	62.8	28.2
2006	91.0	51.3	39.7
2007	90.0	43.6	46.4
2008	89.0	38.1	50.9

SOURCE: Canadian Energy Research Institute.

APPENDIX H
ENERGY PRICE FORECASTS

H.1 Low Case Energy Prices

H.2 Base Case Energy Prices

H.3 High Case Energy Prices



H.1 LOW CASE ENERGY PRICES



TABLE H.1
LOW CASE ENERGY PRICES
(1986 \$Cdn. per barrel)

Year	Light Crude Oil				Heavy Oil	Heavy Blend	Synthetic Crude	Bitumen Blend	Bitumen	Natural Gasb
	Chicagoa	Alberta	Toronto	Maritimes						
1988	16.50	18.85	20.35	20.37	13.18	15.30	19.85	13.53	8.53	1.75
1989	11.18	12.28	13.78	13.80	6.67	8.73	13.28	6.96	2.12	1.84
1990	10.00	10.83	12.33	12.35	4.86	6.97	11.83	5.20	0.24	2.06
1991	10.50	11.61	13.11	13.13	5.19	7.37	12.61	5.60	0.43	2.26
1992	11.00	12.23	13.73	13.75	5.44	7.68	13.23	5.91	0.57	2.36
1993	12.01	13.49	14.99	15.01	6.32	8.63	14.49	6.86	1.34	2.47
1994	14.29	16.34	17.84	17.86	8.78	11.17	17.34	9.40	3.65	2.59
1995	15.56	17.93	19.43	19.45	9.98	12.45	18.93	10.68	4.72	2.71
1996	16.90	20.15	21.65	21.67	11.59	14.16	21.15	12.39	6.14	2.83
1997	18.30	21.94	23.44	23.46	12.99	15.64	22.94	13.87	7.41	2.96
1998	19.81	23.88	25.38	25.40	14.53	17.25	24.88	15.48	8.82	3.10
1999	21.32	25.81	27.31	27.33	16.07	18.87	26.81	17.10	10.22	3.24
2000	22.96	27.92	29.42	29.44	17.78	20.65	28.92	18.88	11.79	3.39
2001	23.83	29.03	30.53	30.55	18.51	21.45	30.03	19.68	12.40	3.65
2002	24.74	30.20	31.70	31.72	19.28	22.29	31.20	20.52	13.06	3.90
2003	25.68	31.40	32.90	32.92	20.10	23.18	32.40	21.41	13.75	4.16
2004	26.65	32.65	34.15	34.17	20.95	24.10	33.65	22.33	14.48	4.33
2005	27.59	33.85	35.35	35.37	21.77	24.99	34.85	23.22	15.18	4.53
2006	28.55	35.08	36.58	36.60	22.99	26.22	36.08	24.45	16.38	4.75
2007	29.55	36.36	37.86	37.88	24.26	27.50	37.36	25.73	17.63	4.96
2008	30.59	37.70	39.20	39.22	25.58	28.83	38.70	27.06	18.93	5.15

SOURCE: Canadian Energy Research Institute

^aConstant 1986 \$U.S. per barrel.

^bConstant 1986 \$Cdn. per Mcf.



H.2 BASE CASE ENERGY PRICES



TABLE H.2

BASE CASE ENERGY PRICES
(1986 \$Cdn. per barrel)

Year	Light Crude Oil				Heavy Oil	Heavy Blend	Synthetic Crude	Bitumen Blend	Bitumen	Natural Gas ^b
	Chicago ^a	Alberta	Toronto	Maritimes						
1988	16.50	18.85	20.35	20.37	13.18	15.30	19.85	13.53	8.53	1.75
1989	18.54	21.37	22.87	22.89	15.67	17.82	22.37	16.05	10.98	1.84
1990	19.40	22.43	23.93	23.95	16.36	18.57	23.43	16.80	11.55	2.06
1991	19.82	23.26	24.76	24.78	16.73	19.02	24.26	17.25	11.79	2.26
1992	20.69	24.34	25.84	25.86	17.44	19.80	25.34	18.03	12.38	2.36
1993	21.06	24.81	26.31	26.33	17.53	19.95	25.81	18.18	12.36	2.47
1994	21.78	25.71	27.21	27.23	18.06	20.53	26.71	18.76	12.77	2.59
1995	22.53	26.64	28.14	28.16	18.62	21.16	27.64	19.35	13.22	2.71
1996	23.65	28.80	30.30	30.32	20.17	22.82	29.80	21.05	14.58	2.83
1997	24.69	30.13	31.63	31.65	21.11	23.83	31.13	22.06	15.40	2.96
1998	25.42	31.07	32.57	32.04	21.66	24.45	32.07	22.68	15.83	3.10
1999	26.15	32.01	33.51	33.53	22.21	25.06	33.01	23.29	16.26	3.24
2000	26.90	32.97	34.47	34.49	22.78	25.70	33.97	23.93	16.72	3.39
2001	27.78	34.10	35.60	35.62	23.52	26.51	35.10	24.74	17.34	3.65
2002	28.70	35.27	36.77	36.79	24.31	27.37	36.27	25.60	18.01	3.90
2003	29.65	36.49	37.99	38.01	25.14	28.27	37.49	26.50	18.71	4.16
2004	30.63	37.75	39.25	39.27	26.01	29.20	38.75	27.43	19.46	4.33
2005	31.64	39.04	40.54	40.56	26.92	30.18	40.04	28.41	20.24	4.53
2006	32.69	40.39	41.89	41.91	28.25	31.52	41.39	29.75	21.55	4.75
2007	33.76	41.76	43.26	43.28	29.61	32.90	42.76	31.13	22.89	4.96
2008	34.88	43.20	44.70	44.72	31.03	34.33	44.20	32.56	24.29	5.15

SOURCE: Canadian Energy Research Institute

^aConstant 1986 \$U.S. per barrel.^bConstant 1986 \$Cdn. per Mcf.



H.3 HIGH CASE ENERGY PRICES



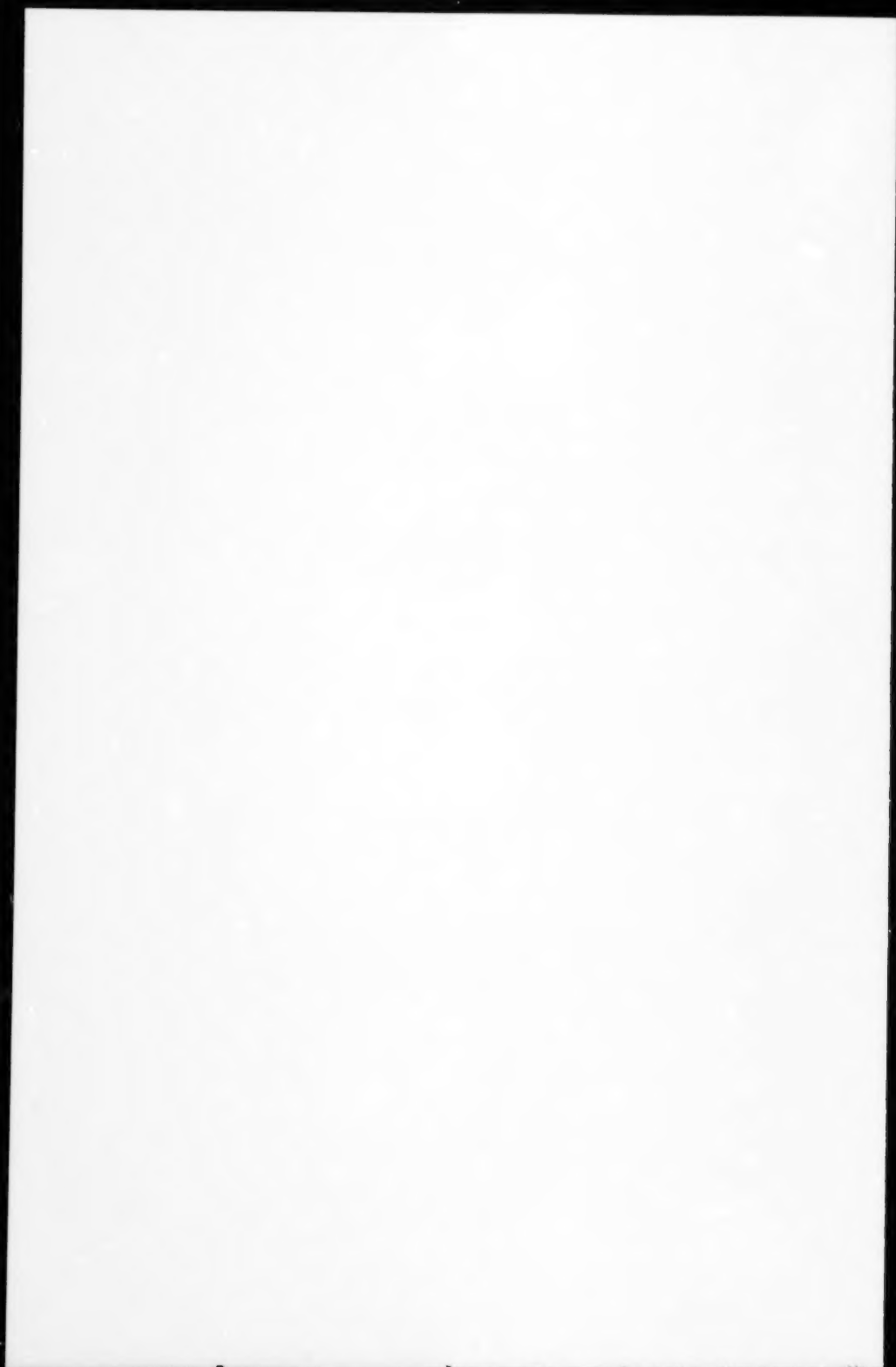
TABLE H.3
HIGH CASE ENERGY PRICES
(1986 \$Cdn. per barrel)

Year	Light Crude Oil				Heavy Oil	Heavy Blend	Synthetic Crude	Bitumen Blend	Bitumen	Natural Gasb
	Chicago ^a	Alberta	Toronto	Maritimes						
1988	16.50	18.85	20.35	20.37	13.18	15.30	19.85	13.53	8.53	1.75
1989	19.50	22.55	24.05	24.07	16.85	19.01	23.55	17.24	12.14	1.84
1990	20.50	23.79	25.29	25.31	17.71	19.93	24.79	18.16	12.88	2.06
1991	21.50	25.36	26.86	26.88	18.81	21.12	26.36	19.35	13.84	2.26
1992	22.30	26.36	27.86	27.88	19.44	21.81	27.36	20.04	14.34	2.36
1993	23.10	27.36	28.86	28.88	20.06	22.50	28.36	20.73	14.85	2.47
1994	24.10	28.61	30.11	30.13	20.93	23.43	29.61	21.66	15.60	2.59
1995	25.10	29.86	31.36	31.38	21.80	24.37	30.86	22.60	16.35	2.71
1996	26.30	32.20	33.70	33.72	23.53	26.22	33.20	24.45	17.89	2.83
1997	27.20	33.35	34.85	34.87	24.30	27.05	34.35	25.28	18.53	2.96
1998	28.20	34.63	36.13	36.15	25.19	28.01	35.63	26.24	19.30	3.10
1999	29.10	35.79	37.29	37.31	25.96	28.84	36.79	27.07	19.95	3.24
2000	30.00	36.94	38.44	38.46	26.72	29.68	37.94	27.91	20.59	3.39
2001	31.05	38.29	39.79	39.81	27.68	30.70	39.29	28.93	21.42	3.65
2002	32.14	39.69	41.19	41.21	28.69	31.78	40.69	30.01	22.31	3.90
2003	33.26	41.12	42.62	42.64	29.73	32.90	42.12	31.13	23.23	4.16
2004	34.43	42.62	44.12	44.14	30.84	34.08	43.62	32.31	24.21	4.33
2005	35.63	44.16	45.66	45.68	31.98	35.29	45.16	33.52	25.23	4.53
2006	36.88	45.76	47.26	47.28	33.57	36.90	46.76	35.13	26.79	4.75
2007	38.17	47.42	48.92	48.94	35.21	38.55	48.42	36.78	28.40	4.96
2008	39.50	49.12	50.62	50.64	36.90	40.25	50.12	38.48	30.06	5.15

SOURCE: Canadian Energy Research Institute

^aConstant 1986 \$U.S. per barrel.

^bConstant 1986 \$Cdn. per Mcf.



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